31 March 2011

Project TransmiT: Impact of Uniform Generation TNUoS

Prepared for RWE npower

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Executive Summary

Overview

We have been commissioned by RWE npower ("RWE") to compare the current system of locational transmission network use of system (TNUoS) charges for GB power generators with a system of uniform generator charges.

The British electricity system needs major investment in new generation and transmission capacity over the next two decades to meet the government's green targets and ensure security of supply. On the generation side, this investment includes a requirement for massive expansion of renewables and other low-carbon generation, as well as major new investment in gas-fired plant – our own estimates are that GB needs 30GW of new low-carbon generation and 33GW of new gas-fired investment by 2030. For both these types of investment, investors have a wide choice of where to locate their plant, and the choices made by investors will have significant implications for the cost of generation and transmission investment, as well transmission congestion and losses.

Our analysis demonstrates that moving to a uniform TNUoS charge would incentivise investment to locate in more remote parts of GB where, for example, load factors for wind generation are highest and access to gas is cheapest. We estimate this change in investment patterns would substantially increase generation and transmission costs in GB, resulting in a net cost to consumers of £20 billion in NPV terms relative to a system with locational generation TNUoS. At the same time, we find no significant difference in performance between the two charging regimes in terms of CO2 emissions and the achievement of the UK target for 30% of renewables in electricity consumption by 2020.

Hence, we conclude the current system of locational generation TNUoS is economically efficient relative to a uniform charge, and sustainable in terms of meeting the UK government's green targets.

Our Assignment

Ofgem recently initiated a review of electricity and gas transmission charging and access arrangements for Great Britain (GB). In this context, we have been commissioned by RWE to compare the current system of locational TNUoS charges for GB power generators with a system of uniform generator charges. The impacts we were asked to assess are (a) changes in total avoidable power sector costs, and (b) changes in customer bills over the period to 2030. As an adjunct, we have also reviewed any differences between the two scenarios in terms of achieving government renewables and CO2 reduction targets.

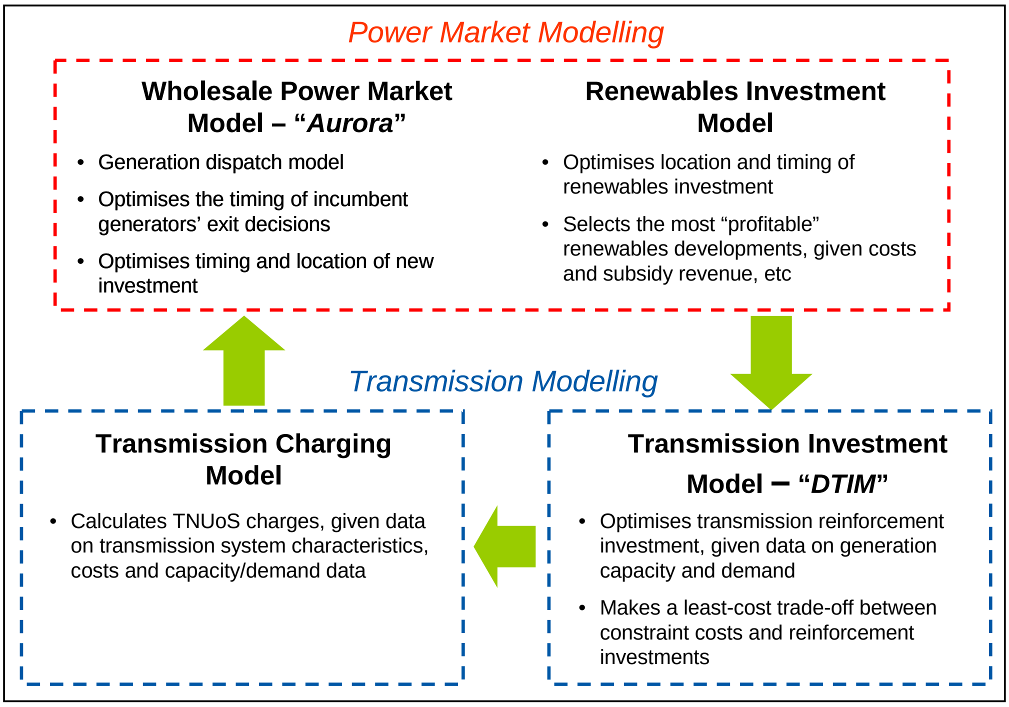
To provide the evidence needed for this assessment, we have undertaken detailed modelling of the GB wholesale power market and the GB transmission system under locational and uniform TNUOS scenarios defined as follows:

- **Locational scenario:** we assume the current transmission charging regime continues indefinitely, with a locational wider charge for generators connected to the GB transmission system per kW of Transmission Entry Capacity (TEC), and a locational charge reflecting the costs of local transmission assets.

- **Uniform scenario:** we assume that all generators pay a uniform "postage stamp" transmission access charge per kW of TEC, with no separate local asset charges, so that all generators including offshore and island generators pay a single £/kW charge that is invariant to their location on the GB transmission system.

To compare the locational and uniform generation TNUoS charging regimes, we have developed a modelling framework that combines wholesale power market models with models of transmission investment requirements and TNUoS charges, as illustrated in Figure 1. Given the interdependency between generation investment decisions, both entry and exit, and transmission investment and charges, we iterated between the transmission system and wholesale power market models to identify a long-term equilibrium pattern of investment and charges.

Figure 1: Overview of Modelling Framework



Source: NERA/Imperial Analysis

Process for Defining Assumptions

To define the modelling assumptions required to calibrate our models we relied on publicly available sources as far as possible, and where possible we have used assumptions from recent studies published or commissioned by the UK government. As well as UK government sources, we have relied on documents and data published by National Grid, the Energy Networks Strategy Group (ENSG), Renewables UK and Ofgem to define modelling assumptions. We have not relied on proprietary data provided by RWE npower.[1]

[1] RWE npower did supply us with some data, but in all cases it was data that we could have obtained in the public domain, e.g. through the Balancing Mechanism Reporting System (BMRS).

Given the time required to define assumptions, conduct modelling and document our findings, we used a "data freeze" of 3 December 2010. Hence, we have not accounted for changes in government policy or market conditions that came to light after this date, including the government's recent proposals on Electricity Market Reform (EMR).

In areas where we could not objectively define assumptions using government or other published sources, we took a "conservative" approach of selecting modelling assumptions that will tend to minimise the estimated difference in costs between the locational and uniform charging models. For example:

- We assumed that generators bid into the balancing mechanism at their short-run marginal cost of generation, ignoring unit commitment costs, dynamic constraints and the impact of market power which may result in spreads between their bid and offer prices, which will tend to under-state constraint costs. Due to the higher constraint costs in the uniform scenario, we would expect that assuming a non-zero bid-offer spread would increase costs more in the uniform than the locational scenario;
- We assume that new transmission infrastructure comes online as soon as our modelling suggests it is required. In reality, delays in commissioning new transmission lines (e.g. due to planning delays) may increase costs. Due to the higher requirement for new transmission investment in the uniform case, delays in developing new infrastructure would increase transmission system costs by more in the uniform than the locational scenario; and
- To estimate transmission investment costs, we used an average investment cost of £50/MW/km/yr which is the lowest cost estimate that National Grid uses in its own modelling with DTIM.[2] We may therefore have understated the true difference in costs between the uniform and locational scenarios.

Summary of Modelling Results

Investment patterns

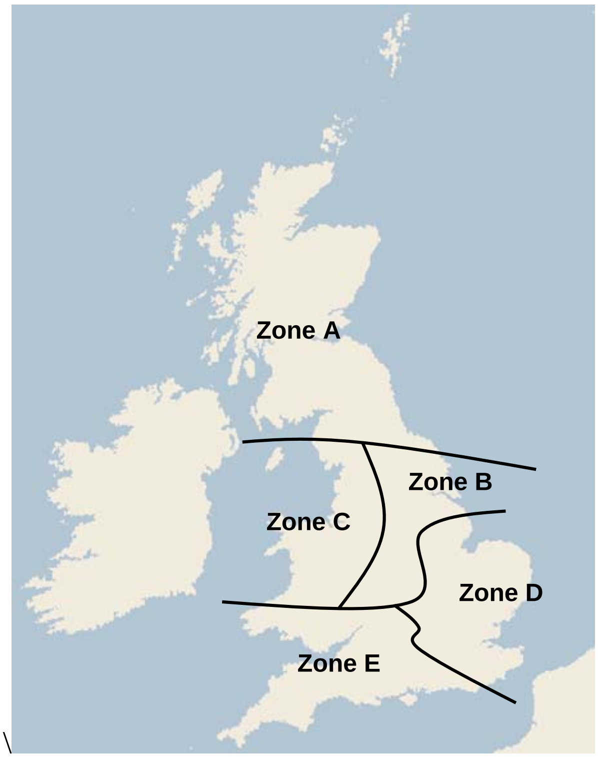
In both scenarios our models predict investment in a range of new renewable, nuclear, CCGT and OCGT generation capacity, with a similar mix of technologies in both cases. However, as Figure 3 and Figure 4 show, there is a significant impact on the locational decisions of new conventional and renewable generators. In the locational scenario, new conventional generation capacity locates in BMRS zone D (see Figure 2), which is close to the major load centres in the south east, with some investment in the south west and the midlands, in response to low TNUoS charges in these areas of the country. Renewables development is spread across all areas of the country. New nuclear capacity is developed in zone C, driven by falling TNUoS charges in the midlands and northern England towards the end of the modelling horizon.

In contrast, in the uniform scenario, our models predict that renewables investment will be more heavily concentrated in Scotland and offshore in the North Sea, with very little wind development onshore in England and Wales. New conventional generation locates along the

[2] DTIM User Report, Qiong Zhou and Paul Plumptre, National Grid, 30 September 2009.

east coast of England and Scotland and in south Wales where access to gas is cheapest. The ability to avoid local asset charges also incentivises a shift in offshore wind development to sites that are located further from shore, and incentivises more wind development on the Scottish islands, albeit some wind capacity is developed on the islands in both locational and uniform scenarios. In the uniform case, we assume new nuclear capacity would be located at sites where current projects to develop new nuclear plants are most advanced, i.e. they have the closest announced commissioning dates, given we assume there is no difference in cost between the sites in this scenario.

Figure 2: Map of BMRS Zones



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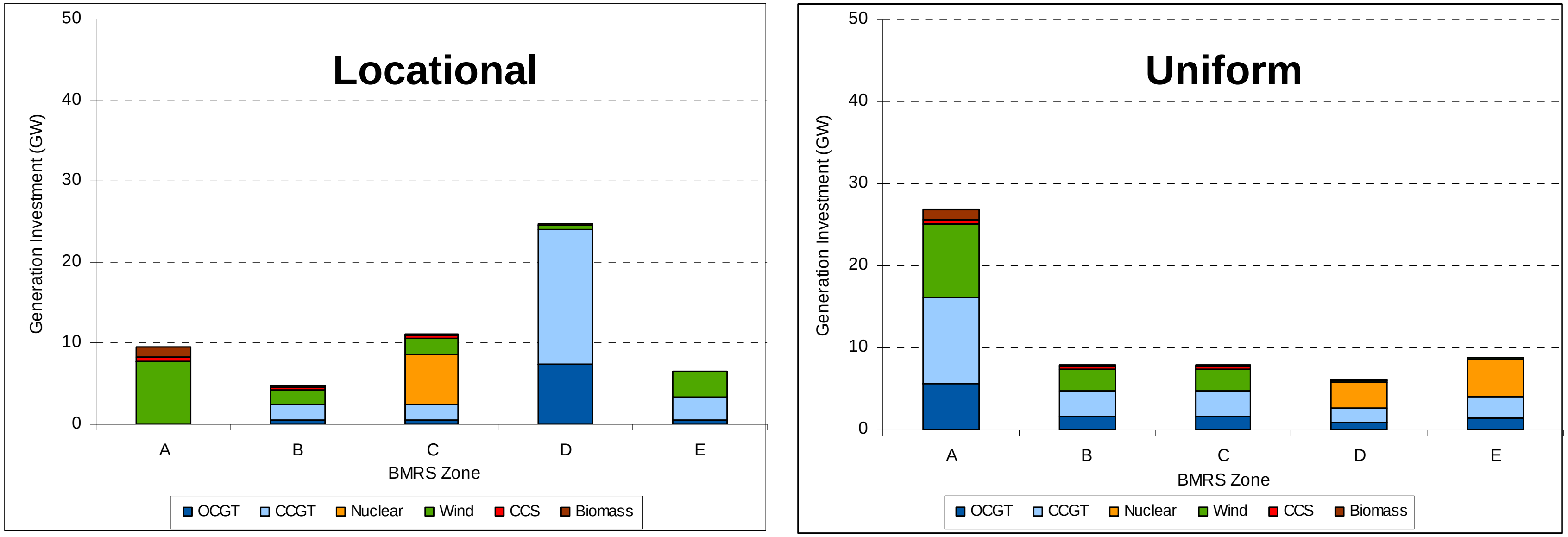
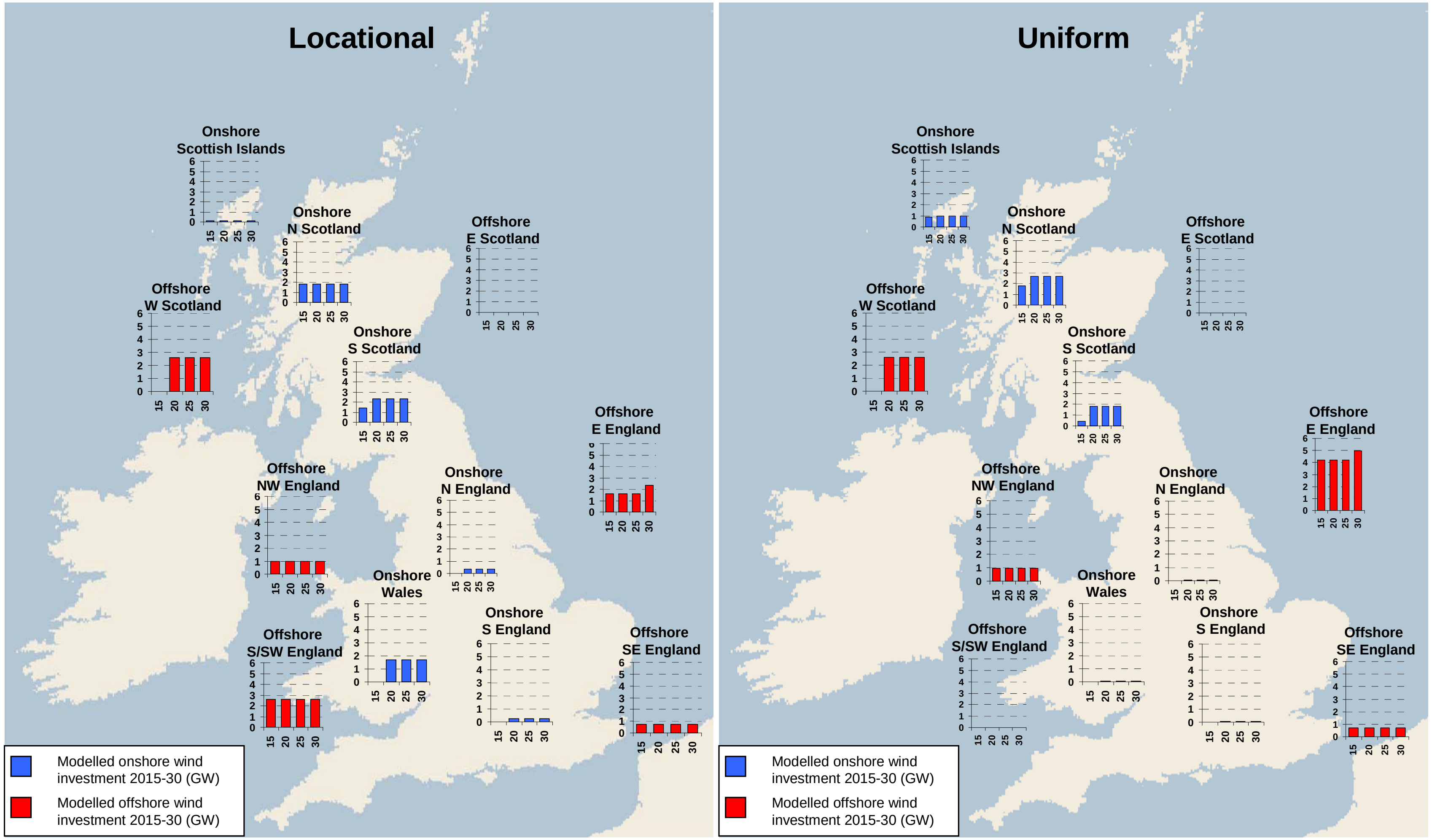
Source: NERA/Imperial Analysis

Figure 3: Location of Modelled Generation Investment



Source: NERA/Imperial Analysis

Figure 4: Location of Modelled Renewables Investment

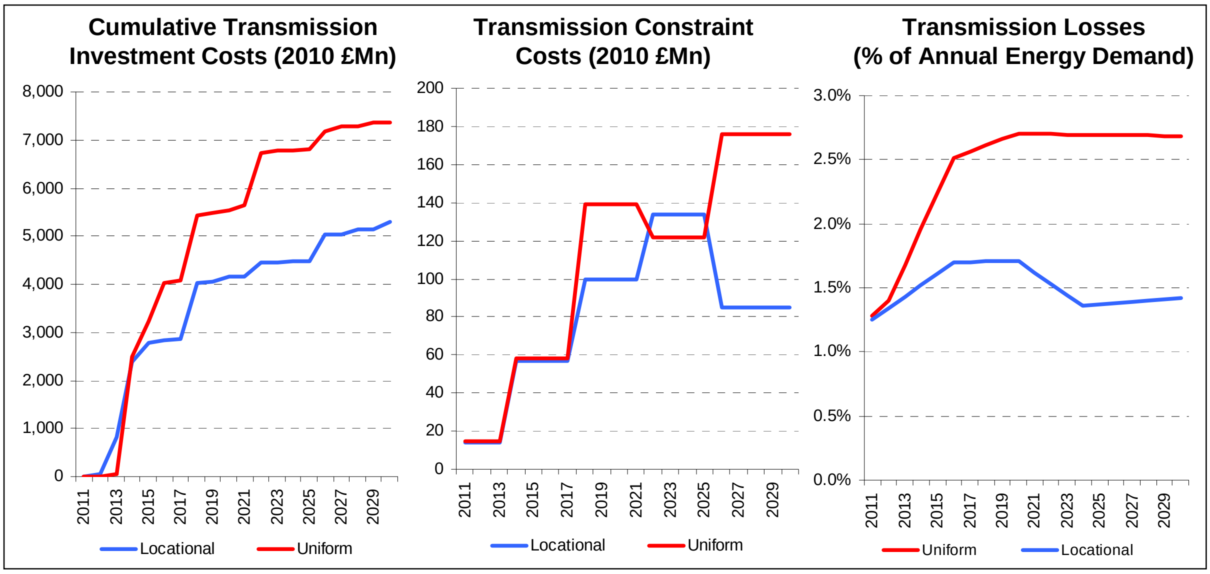


Source: NERA/Imperial Analysis

The Impact on Transmission System Costs

As Figure 5 shows transmission investment costs, constraint costs and losses are substantially higher in the uniform scenario than in the locational scenario.

Figure 5: Transmission System Costs



Source: NERA/Imperial Analysis

The figure shows that cumulative transmission expenditure including both onshore and offshore grid investments, increases by 40% in the uniform scenario when compared to the locational scenario. Investments are higher due to the need for infrastructure to transport energy from more remote locations, both on and offshore, to the main load centres.

Constraint costs are also higher in the uniform scenario, although both scenarios produce estimates of constraint costs that are below current constraint costs in the near-term, and which remain lower than some published projections[3] throughout the modelling horizon. As described above, this occurs due to our assumptions that generators bid into the balancing mechanism at their short run marginal cost of production and that new transmission infrastructure comes online as soon as our modelling suggests it is required, without any delays in commissioning new transmission lines, e.g. due to planning or logistical constraints.

Assuming inefficiency in the construction of new transmission infrastructure would increase the absolute level of constraint costs in both scenarios, and given the higher investment requirements in the uniform case, we would also expect a higher difference in constraint costs between the scenarios. Assuming a spread between generators' bid and offer prices into the balancing mechanism, due to the impact of unit commitment costs or market power, would also increase both the absolute level of constraint costs and the difference between the two scenarios.

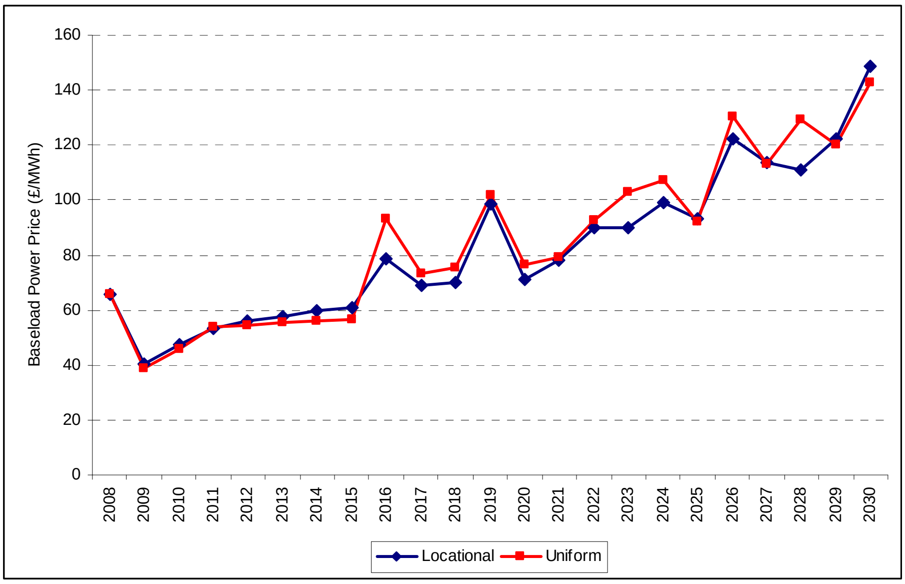
3 See, for example: Impact Assessment of proposals to improve grid access, DECC, 3 March 2010.

Losses increase substantially in the uniform case because a high proportion on the new generation fleet (both renewable and conventional) is developed in the north of GB, and offshore wind capacity tends to be located further offshore. The increased development of offshore HVDC lines in the uniform case also increases losses compared to the locational case, where a higher proportion of modelled transmission reinforcements make use of AC lines.

The Impact on Wholesale Power Prices

Uniform TNUoS charging removes the possibility for new entrant CCGTs and OCGTs to locate in zones with negative TNUoS charges, which increases the costs they need to recover through power market prices in order to enter the market. This effect increases long-term power prices, as Figure 6 shows.

Figure 6: The Impact on Power Prices (£ Nominal)



Source: NERA/Imperial Analysis

The Impact on Consumers

As a result of higher power prices and higher transmission system costs, we estimate that uniform TNUoS charges would increase costs to consumers by £19.8 billion in NPV terms between 2011 and 2030 compared to the locational scenario. This equates to £3.56 per MWh of energy demand, or around 2.2% of the energy component of 2020 consumer bills.

Our modelling indicates that current government subsidies schemes are sufficient to incentivise the renewables investment required to meet the government's target for 30% of renewables in power generation by 2020 in both the locational and uniform scenarios. There is also no material difference between the two scenarios in terms of the outlook for GB CO2 emissions. Hence, there are no benefits from the introduction of uniform charges.

Table 1: Estimated Impact on Consumers (Real 2010 £)

NPV to 2030 @ 3.5%, 2010 Prices	**£Mn**	**£/MWh**
Wholesale Purchases	13,899	2.50
Renewable Subsidies	262	0.05
Losses	4,082	0.74
Constraints	344	0.06
Demand TNUoS Charges	1,181	0.21
Total	**19,768**	**3.56**

Source: NERA/Imperial Analysis

Alternative Investment Patterns

Although we achieved convergence in our estimated TNUoS charges in the majority of TNUoS charging zones in the locational scenario, our results exhibited some “flipping” of new conventional generation between the south east (BMRS zone D) and the south west (BMRS zone E) in response to small changes in tariffs between iterations. Such large changes in behaviour in response to small changes in costs arises because the modelling framework shown in Figure 1 is deterministic and optimises investors’ decision-making by developing new generation where it is most profitable, even if the differences in profitability are very small.

Due to a lack of objective data, we have omitted some factors that affect locational decisions, such as planning constraints on the availability of suitable sites for developing new generators in a particular region, or the availability of water for cooling. We have also made no allowance for connection policies implemented by National Grid that might direct generators not to connect in some areas, which would offset the incentives provided by TNUoS charges. Therefore, a wider geographic dispersion of new conventional generators may emerge than suggested by our modelling, which may reduce the differences between the scenarios and hence the welfare impacts of a move to uniform TNUoS.

In practice the effects of some small changes are also relatively small when measured by their effect on total costs. For example, shifting the portfolio of new OCGT and CCGT generation capacity between the south east and the south west changes our estimated impact on consumers from the introduction of uniform TNUoS by £0.8 billion in NPV terms (less than 5% of the overall impact), even though this would require significant reinforcement of the grid in the south of England.

Hence, overall transmission system costs are similar irrespective of where the new conventional capacity is located in the south of GB. We obtain this result because the main driver of increased transmission system costs is the increased proportion of generation (both conventional and renewable) that locates in Scotland in the uniform scenario. Hence, our modelling results suggest that locating a larger proportion of new OCGT and CCGT investment in the midlands, for example, rather than in the south east or south west would have only a small impact on costs in the locational scenario, and so does not affect our estimate of the additional costs arising in the uniform scenario.

However, to account for this limited instability of our results, we calculated our estimated impacts on the consumer using the average cost estimates resulting from the final and penultimate runs of our locational scenario.

Conclusion

Our results indicate that the current model for generation TNUoS charging incentivises generation to locate in transmission charging zones situated in the south of GB close to the areas of net demand. Also, the current charging regime, and the use of local asset charges in particular, incentivises new wind generators to make a trade-off between the load factors achievable in an area and the costs of connecting to the transmission system. In contrast, the removal of cost-reflective signals from transmission pricing in the uniform case means generators ignore the costs they impose on the transmission system (or the costs their presence on the system allows the TSO to avoid) in making their locational decisions.

Our modelling also indicates that in the face of significant changes facing the electricity industry in coming years, such as increasing intermittency and an increasing proportion of generation located offshore, the locational charging regime continues to incentivise a more efficient location of new generation capacity on the transmission system when compared to the uniform charging scenario. Locational TNUoS charges continue to represent the incremental (or decremental) cost of reinforcing the transmission system due to the presence of generation capacity in a given zone. Our modelling also suggests that government renewables and CO2 reduction targets are achievable in the locational scenario.

Hence, we conclude the current system of locational generation TNUoS is economically efficient relative to a uniform charge, and sustainable in terms of meeting the UK government’s green targets.

1. Introduction

1.1. Context

The British electricity system needs major investment in new generation and transmission capacity over the next two decades to meet the government's green targets and ensure security of supply. On the generation side, this investment includes a requirement for massive expansion of renewables and other low-carbon generation, as well as major new investment in gas-fired plant – our own estimates are that GB needs 30GW of new low-carbon generation and 33GW of new gas-fired investment by 2030. Against this backdrop, Ofgem recently initiated a review of electricity and gas transmission charging and associated connection agreements for Great Britain (GB).

Because investors have a wide choice of where to locate their plant, the choices made by investors will have significant implications for the cost of the generation and transmission investment required in the GB electricity market, as well transmission congestion and losses, the costs of delivering the investment. Hence, the signals conveyed to investors through the electricity transmission charging model may significantly affect the costs of delivering the investment over the next 10-20 years.

1.2. Our Assignment

We have been commissioned by RWE npower ("RWE") to compare the current system of locational electricity transmission network use of system (TNUoS) charges for GB power generators with a system of uniform generator charges, examining the impact of investors' decisions in responses to two approaches. To compare these charging models, we have been asked to assess (a) changes in total avoidable power sector costs, and (b) changes in customer bills over the period to 2030. As an adjunct, we have also reviewed any differences between the two scenarios in terms of achieving government renewables and CO2 reduction targets.

To provide the evidence needed for this assessment, we have undertaken detailed modelling of the GB wholesale power market and the GB transmission system under locational and uniform TNUOS scenarios defined as follows:

- **Locational scenario:** we assume the current transmission charging regime continues indefinitely, with locational charges for generators connected to the GB transmission system, and all generators paying a charge reflecting the costs of their local transmission assets.
- **Uniform scenario:** we assume that all generators pay a uniform "postage stamp" transmission access charge per MW of transmission entry capacity, with no separate local asset charges, i.e., all transmission costs allocated to GB generators are socialised into a single £/MW charge both for onshore and offshore sites.

In terms of demand TNUoS charges, we were asked to assume that the current system of locational demand charges remains in place independent of changes to generation TNUoS charges. Similarly, we were also asked to assume that the current system of locational gas transportation charges remains in place independent of changes to generation TNUoS charges.

We assume that the existing energy-only wholesale market arrangements and existing renewables obligation scheme remain in place throughout the modelling horizon. Since we started our work for RWE last October, the government has published its proposals for electricity market reform (EMR). However, these proposals are still under discussion and hence we have not factored them into our analysis.

The remainder of this report is structured as follows:

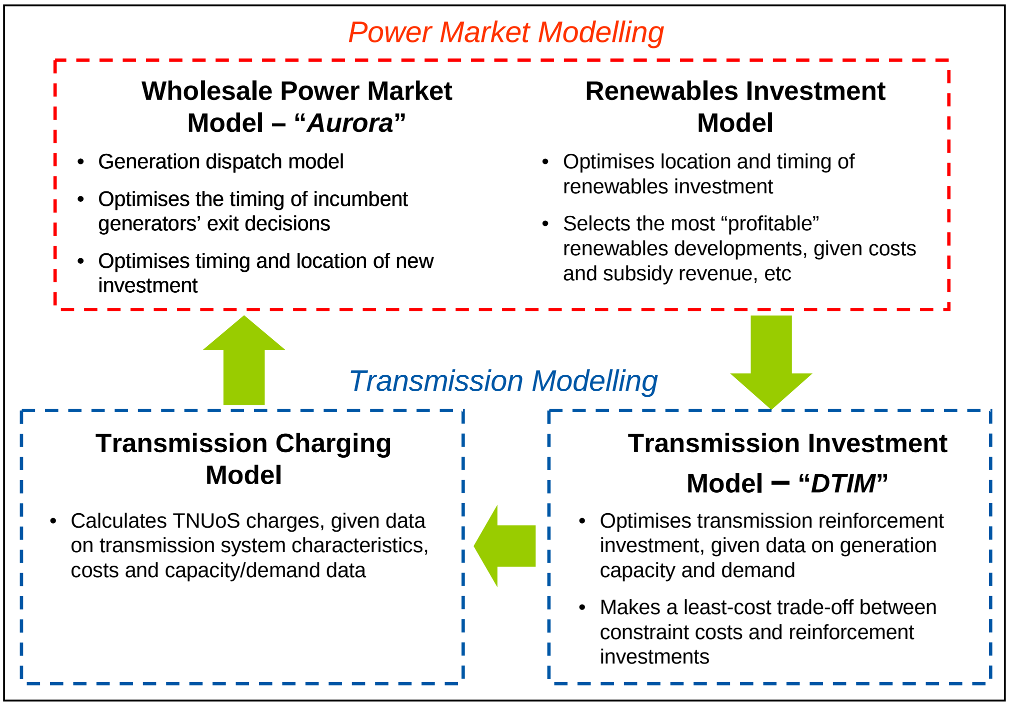
- Chapter 2 describes our methodology and approach;
- Chapter 3 describes our key modelling assumptions, including a more detailed description of the locational and uniform scenarios;
- Chapter 4 presents the results of the locational scenario;
- Chapter 5 presents the results of the uniform scenario;
- Chapter 6 analyses the welfare effects of the two scenarios; and
- Chapter 7 concludes.

2. Methodology

2.1. Modelling Framework

To compare the locational and uniform generation TNUoS charging regimes, we have developed a modelling framework that combines wholesale power market models with models of transmission investment requirements and TNUoS charges. Figure 2.1 provides a high-level description of our modelling tools and framework.

Figure 2.1
Overview of Modelling Framework



Source: NERA/Imperial Analysis

To model the evolution of the wholesale power market we used the *AURORAxmp*® market model ("Aurora") vended by EPIS Inc. of the US. Although Aurora has the capability to optimise renewables investment simultaneously with conventional generation, the volume of data needed to cover all the choices of location and type of renewables made this approach impractical in terms of run times. We therefore created a separate model to optimise investment in renewable generation capacity that works in tandem with Aurora. Both these models use assumptions on a range of fundamental market drivers, such as the volume and characteristics of existing generation capacity, commodity prices, the costs of new generation capacity and electricity demand growth, as well as assumptions on TNUoS charges.

To model optimal operation and investment in the transmission system we used Imperial's Dynamic Transmission Investment Model (DTIM), which uses locational generation and demand data as an input. Using the forecast of transmission investment from DTIM, we then computed TNUoS charges for the period to 2030 using the National Grid charging model for the locational scenario, and our own bespoke charging model for the uniform scenario.

The assessment we present in this report results from a series of iterations between our models of the wholesale electricity market, which predict the location and quantity of generation investment for a given forecast of TNUoS charges, and our models of the transmission system, which estimate TNUoS charges for a given pattern of generation investment.

2.2. Modelling Tools

2.2.1. Power market modelling tools

As described above, we use Aurora to model entry and exit decisions by conventional generators in the wholesale power market. However, the complexity of investment decisions for new renewable capacity means that we used a separate optimisation model to predict patterns of renewable generation investment.

- **Aurora wholesale market model**

Aurora is a detailed chronological model that simultaneously optimises dispatch and entry and exit decisions (i.e., investment). It selects patterns of generator despatch accounting for both variable costs of production (fuel and CO2 costs, variable O&M costs etc) and unit commitment costs (minimum stable generation, ramp rates, start-up costs etc). The model accounts for unit commitment costs by only "committing" a unit when it expects to earn sufficient margins to recover its unit commitment costs over the following week through power market sales.

Simultaneously, Aurora uses an iterative algorithm to project entry/exit decisions, based on an assessment of the profitability of existing and future generation capacity. The entry/exit decisions and prices that result from this algorithm represent an economic equilibrium in which all generators that find it profitable to remain in the market or enter the market earn sufficient margins in present value terms to cover their fixed costs, including any capital costs. As the model sets the market clearing price equal to system marginal cost in every hour, generators recover their fixed costs in periods when they are infra-marginal with respect to the marginal price-setting plant and in periods of scarcity (i.e. when prices rise higher to ration demand to match the available supply).

- **Renewables investment model**

We used our renewables investment model to predict patterns of investment in new onshore and offshore wind capacity until 2030. The model uses a linear program to select wind investments that maximise an aggregate profit function subject to constraints, such as constraints on the availability of sites for developing wind farms. Hence, we model the behaviour of wind investors on the assumption that they maximise the profitability of new wind investments. The model chooses from onshore wind developments across the whole of Great Britain (including the Scottish Islands), as well as from all "round 2", "round 3" and Scottish Territorial Waters offshore sites.

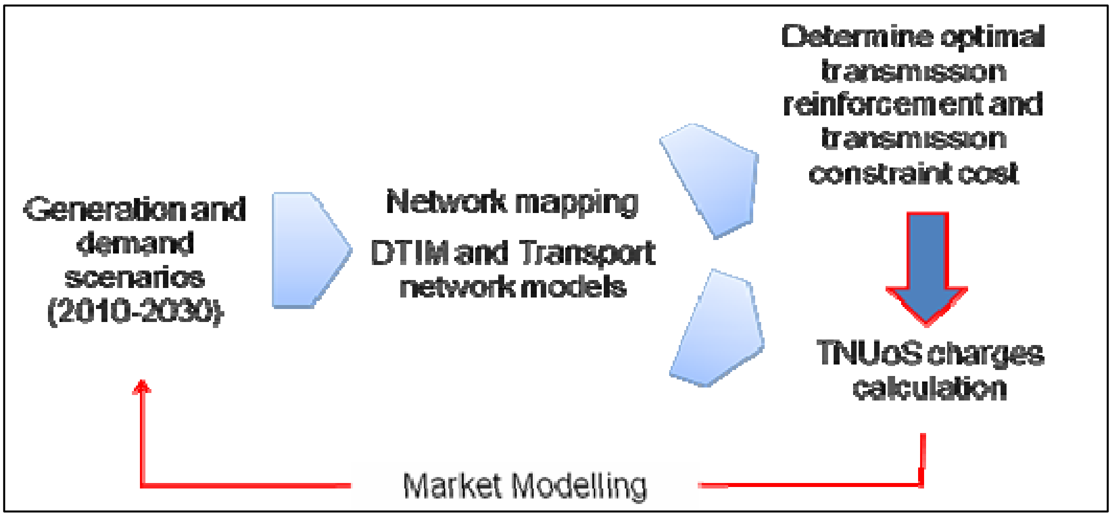
To calculate the profitability of new wind investments, the model uses assumptions on the costs of developing and operating new wind generators, representative hourly production profiles and load factors by zone, and the subsidy and power market revenues earned per

MWh of production. We calibrated the estimated power market revenues using outputs from runs of the Aurora wholesale market model. We estimated subsidy costs on the assumption that all new wind investments benefit from subsidies under the renewables obligation (RO), and that onshore and offshore wind generators continue to receive 1 and 2 renewables obligation certificates (ROCs) per MWh respectively.

2.2.2. Transmission system modelling tools

We calculated transmission investment and charges using two tools: the Dynamic Transmission Investment Model (DTIM) developed by Imperial College and the DCLF Transport Model developed by National Grid. We used DTIM to optimise investments in transmission reinforcements, and to estimate constraint costs and transmission losses for the modelling period. We then passed annuitized transmission investment costs on to the Transport Model to compute the TNUoS wider and local charges per TNUoS generation and demand zone. We then passed TNUoS charges on to the market modelling tools, as illustrated in Figure 2.2.

Figure 2.2
Transmission and Charges Modelling Framework

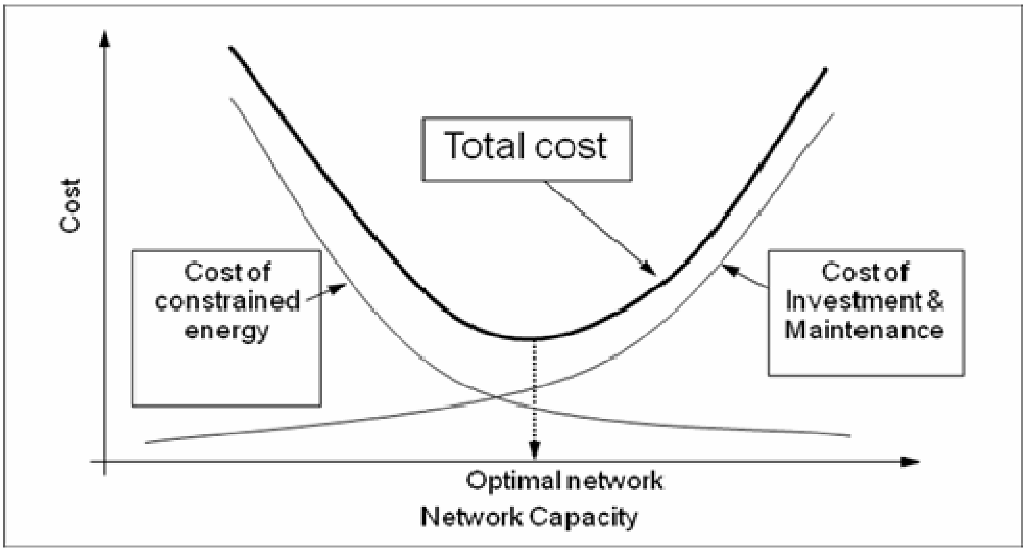


Source: NERA/Imperial Analysis

- **Dynamic Transmission Investment Model (DTIM)**

DTIM is a model developed by Imperial College/SEDG with the purpose of supporting optimal transmission investment decisions on the transmission system in Great Britain. DTIM balances costs of network constraints with costs of network reinforcement, minimising the overall cost of power system operation and expansion over a given duration (e.g. the next twenty years). Throughout the optimization period the model determines when, where and how much to invest using data inputs including a demand forecast, current and future fuel costs, bids and offer prices, evolution of installed generation capacity, the location and quantity of new wind capacity, transmission and generation maintenance plans, etc.

Figure 2.3
DTIM Cost Benefit Analysis



Source: Imperial Analysis

For this assignment, we divided the 2010-2030 modelling horizon into five “epochs” of four-five years. Investment in transmission capacity can take place at the beginning of each epoch.

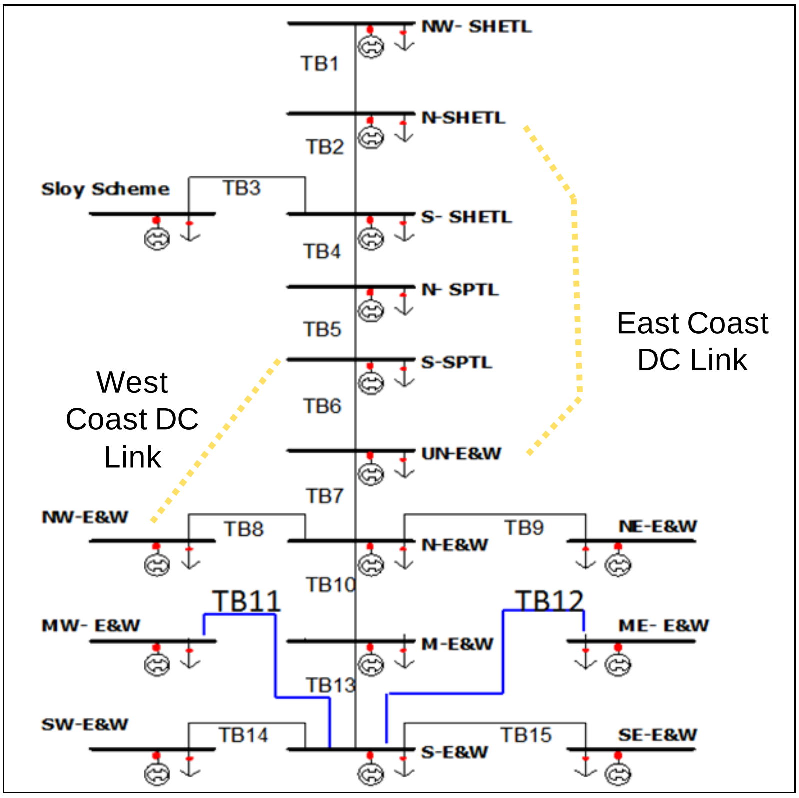
DTIM uses a 16-zone, 15-boundary radial network to represent the GB transmission network, as shown in Figure 2.4. Each node represents a GB zone, and each branch represents a boundary. The network was developed by Imperial College and has been used extensively in the past for supporting the Transmission Access Review (TAR), the fundamental review of the SQSS,[4] and by National Grid to carry out a validation cost benefit analysis exercise for the ENSG proposed projects. We have also included the Western and Eastern DC links in the model, and allowed DTIM to optimise the timing and capacity of these “bootstrap” investments.

We provide representative snapshots of DTIM, as well as a description of the transmission boundaries, zones and the inputs and outputs required by the model in Appendix A.

For this exercise, we calibrated DTIM to National Grid’s “gone green” scenario, as shown in more detail in Appendix B. Specifically, when we inserted the “gone green” assumptions on generation capacity and demand, as well as other modelling parameters, we obtained identical outputs in terms of constraint costs and selected transmission investments.

4 http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode

Figure 2.4
DTIM Radial Network



Source: Imperial Analysis

For each boundary, the model requires data on the thickness, seasonal rating, initial capacity and transmission expansion costs. The expansion cost is a piece-wise linear function which consists of up to 5 sections. The ratings of boundaries are scaled by different factors corresponding to five seasons (Summer, Autumn, Winter, Spring and Maintenance) and windy/non-windy conditions. Each season is divided into 100 snapshots, plus 10 winter peak snapshot ratings, giving 510 boundary ratings for the 510 snapshots in each year.

- **National Grid Transport Model**

The National Grid Transport Model calculates the marginal costs of investment in the transmission system that would be required as a consequence of an increase in demand or generation at each connection point or node, based on a study of peak conditions on the transmission system. Generation is scaled down uniformly so as to be equal to peak demand and the power flows and marginal MWkm (which forms the basis of computing the Long Run Marginal Cost of transmission investment) are computed. Nodes are aggregated and a wider locational TNUoS charge is computed for the 20 generation and 14 demand zones. The charges are then complemented by the local asset charges, a residual charge (so as to recover the total cost of the system set by the Maximum Allowed Revenue) and re-adjusted so as to maintain the 27/73 generation/demand revenue recovery split.

The transport model is available for public use and a detailed description can be found in Chapter 14 of the Connection and Use of System Code (CUSC).

3. Modelling Assumptions

3.1. Process for Defining Assumptions

To define modelling assumptions, we have relied on publically available sources as far as possible, and where possible we have used assumptions from recent studies published or commissioned by the UK government. As well as UK government sources, we have relied on documents and data published by National Grid, the Energy Networks Strategy Group (ENSG), Renewables UK and Ofgem to define modelling assumptions. We have not relied on proprietary data provided by RWE npower.[5]

Given the time required to define assumptions, conduct modelling and document our findings, we used a "data freeze" of 3 December 2010. Hence, we have not accounted for changes in government policy or market conditions that came to light after this date, including the government's recent proposals on Electricity Market Reform (EMR).

3.2. Defining the TNUoS Charging Scenarios

3.2.1. Locational scenario

In general, we defined the locational scenario by rolling forward the charging methodology that is currently in place. However, to roll this charging model forward to 2030 we needed to make assumptions about a number of aspects of the existing charging arrangements that are either currently under review, or that we expect to come under review during our modelling horizon.

As we describe in Appendix C, we considered the following aspects of generation TNUoS charging when defining the locational charging regime:

- **Intermittent generation charging:** We assume the arrangements already in place continue throughout the modelling horizon;
- **Offshore generation charging:** We assume the arrangements already in place continue throughout the modelling horizon;
- **HVDC links charging**: We calculate charges by assuming the DC links are used for residual power flows after optimisation of flows on the AC system (NG's "Required Capacity" option). In the Transport model, DC links are modelled as 275/400kV cables, with the length adjusted to reflect DC link cost as quoted in ENSG report;
- **Interconnector charging:** We assume the arrangements already in place continue throughout the modelling horizon;
- **Island charging:** We assume the same charging arrangements as we assume for OFTO assets; and

5 RWE npower did supply us with some data, but in all cases it was data that we could have obtained in the public domain, e.g. through the Balancing Mechanism Reporting System (BMRS).

- **Embedded generation charging:** We assume the arrangements already in place continue throughout the modelling horizon.

3.2.2. Uniform scenario

When defining the uniform charging scenario, we considered three issues:

1. Whether the TNUoS charge will be charged on a £/MWh or £/kW basis;
2. Whether the costs of local assets, in particular offshore transmission and island connection, will also be recovered through the uniform charge or through a separate local asset charge as under the locational charging regime; and
3. Whether the generation/demand 27/73 split should be preserved.

We assumed that uniform TNUoS charges would be applied on a £/kW basis, as under the existing locational charging regime. As uniform charges have been proposed as a means of supporting renewable generation, we assumed that the costs of local assets, such as island connections and offshore grid charges, would be recovered through the uniform charge. Hence, whereas generators currently pay a local asset charge and a “wider” TNUoS charge, we assume in the uniform scenario that all generators including offshore and island generators would pay one £/kW charge that does not depend on the generator’s location on the onshore or offshore transmission system.

Finally, as changing the generation/demand split would not materially affect the choice between generation technologies or their locational decisions, and we preserved the current 27/73 split for consistency with the locational scenario. Hence, in each the uniform charge is set at a level that allows the transmission companies to recover 27% of their revenue requirement through the uniform generation TNUoS charge.

3.3. Accounting for Government Policy

Our modelling approach takes into account the UK government’s targets for reducing CO2 emissions from the power sector, and increasing the share of renewables in the generation mix, as well as targets for the deployment of other low carbon generation technologies.

3.3.1. CO2 emissions targets

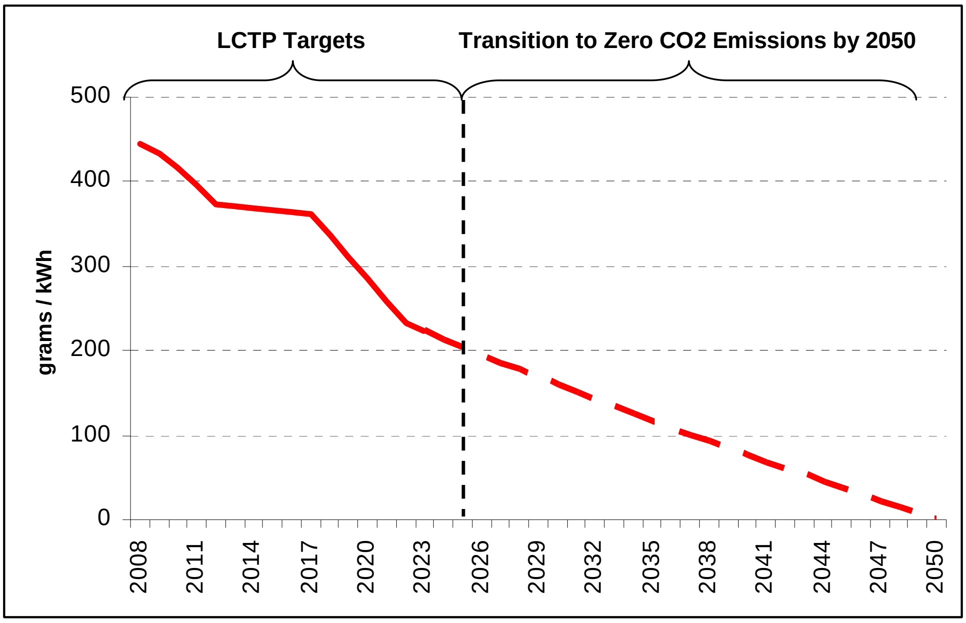
The Climate Change Act 2008 requires that the UK reduce greenhouse gas emissions by 80% compared to 1990 levels by 2050, and requires that the government publish 5-year carbon budgets describing how it will meet this target. Carbon budgets for the period 2008-2022 were implemented through the Carbon Budgets Order 2009. The Carbon Budgets Order 2009 sets targets for total emissions, and the Low Carbon Transition Plan (LCTP) published by DECC in July 2009 breaks down these carbon budgets into sectors. We have used the budgets for the power sector in the LCTP to define CO2 emissions targets for our modelling.

As of the date of our data freeze, the UK government had not yet set carbon budgets for the period after 2022. We therefore assumed that the CO2 target for the power sector will tighten gradually between the end of 2022 and 2030 on a trajectory that would allow CO2 emissions from the power sector to reach zero by 2050. This assumption is consistent with the projections in the 2010 DECC “Pathways” document in which all the scenarios presented imply that CO_2 emissions from the power sector reach zero by 2050, with the exception of the "reference case", where there is "little or no attempt to decarbonise" and the UK falls well short of meeting CO_2 targets.[6]

The resulting CO_2 target we assumed for our modelling horizon reaches around 200 grams of CO_2 per kWh in 2030, as shown in Figure 3.1, and puts the GB power sector on a path to full decarbonisation by 2050. We note that this target is close to the "baseline" scenario used in the EMR document and somewhat higher than the Committee on Climate Change (CCC) recommendations of 50 grams/kWh in 2030, although both these projections were published after our data freeze date.[7]

Because our power market model dispatches generators one week at a time, we were not able to impose binding annual (or multi-annual) emissions constraints. Therefore rather than imposing the target shown in Figure 3.1 as a hard constraint, we ran our model using UK government CO_2 price assumptions (see Section 3.4.5) and examined the results to check whether modelled emissions were within the assumed target. If they were not, we increased our assumed CO_2 price, re-run the model and repeated this procedure until modelled emissions fell within the target.

Figure 3.1
Assumed Target Trajectory for CO2 Emissions from Power Generation



Source: NERA/Imperial Analysis of DECC Data

3.3.2. Targets for renewable generation

EU Directive 2009/28/EC on the promotion of the use of energy from renewable sources requires that the UK increase its share of renewables in gross final energy consumption to

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6 2050 Pathways Analysis, DECC, July 2010, page 30.

7 Electricity Market Reform Consultation Document, DECC, December 2010, figure 1.

15% by 2020. To assess how this target would be achieved, the previous government published the Renewable Energy Strategy (RES) in July 2009, which showed the government's plans for achieving its 15% target by 2020. This document indicated that 49% of the UK's total renewable energy production would have to come from the power sector, which implies that 30% of electricity generation would need to come from renewable sources by 2020.[8]

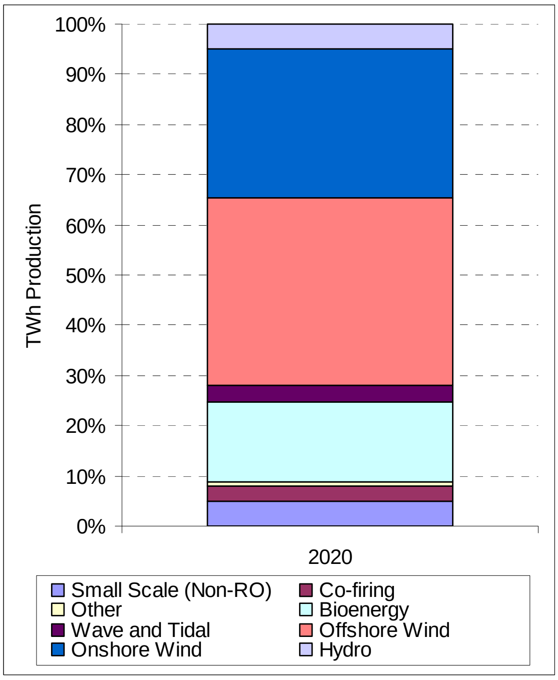
The RES also contains projections of the mix of renewable generation technologies that will be developed to meet the 30% target, as illustrated in Figure 3.2. In particular, the RES assumptions imply that around two thirds of renewable generation in 2020 will come from wind generation, with the remainder coming from a mix of other technologies, including biomass, hydro and other small scale renewables (i.e. microgeneration supported by feed-in tariffs, rather than the RO).

As there is limited information in the public domain regarding how the economics of new biomass, hydro and other renewable technologies differ by location, we have not modelled these investment decisions explicitly. Instead, we assumed that sufficient capacity would come online to meet the targets implied by the RES. We defined assumptions regarding the location of new non-wind investment with reference to the locations of existing capacity and/or projects that are in development and listed in National Grid's 2010 Seven Year Statement (SYS).[9]

8 The UK Renewable Energy Strategy, DECC, July 2009, Chart 2.

9 For example, based on Table 3.6 in the 2010 SYS, we assumed that new biomass capacity will be developed in generation TNUoS zones 5, 6, 7, 8 and 13.

Figure 3.2
Mix of Renewable Generation Technologies Implied by the RES



Source: NERA/Imperial Analysis of data from the RES

New wind capacity will make the largest contribution to meeting the UK renewable generation targets. There is good data available on locational cost differences for wind farms, so, we have explicitly modelled the choice over where, when and how much wind capacity will come online. Using our renewables investment optimisation model, we have used the following procedure:

- We assumed that all existing renewables capacity remains online indefinitely, and that the renewables projects listed as under construction in the SYS come online at the planned dates.[10] We estimated the total energy production that will come from these existing projects and those under construction using assumptions on regional wind load factors (see below for more details on the source of our load factors);
- Based on our electricity demand forecast, we then calculated the difference between the total energy production that will come from these existing projects and those under construction, and the amount that will be needed to meet the government target of sourcing 30% of electricity from renewable sources by 2020; and
- We then used our renewables investment model to select the most profitable onshore and offshore wind generation projects, imposing the constraint that subsidies under the RO are only available to support the quantity of renewables required to generate 30% of electricity in 2020.

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[10] 2010 Seven Year Statement, National Grid Electricity Transmission Limited, Table 3.2.

An important feature of this approach is that we do not constrain the model to build sufficient new wind capacity to meet the 30% target, and it will not do so unless it can develop a sufficient quantity of *profitable* wind farm sites, within the constraints specified in the model. Hence, our approach allows us to assess whether the government's 2020 renewables target is achieved in each scenario.

The model can also choose to develop more wind capacity than is required to meet the 30% 2020 target. However, because we assume that government subsidies (i,e, the RO) only remain in place to support enough investment to meet the 30% target, we assume any such incremental wind investment to provide renewable energy beyond this target would not benefit from any additional subsidy payments outside of the energy market, and so would only be developed if power prices rise to the level required to remunerate new wind generation.

3.3.3. New nuclear power generation

UK government bodies have made various statements about the planned capacity of new nuclear plant that they would like to see, or that they anticipate coming on line:

- At the low-end of the range, in its Project Discovery document Ofgem assumes one 1,600MW EPR is built between 2020 and 2025 ("Slow growth scenario");[11]
- At the top-end of the range, MARKAL modelling conducted for the Committee on Climate Change (CCC) in the summer of 2008 suggested 12,800MW of new nuclear capacity would be built between 2020 and 2025, with a further 1,600MW added before 2030, giving a total of 14,400MW by 2030.[12]

However, most of the statements from government bodies suggest the authorities see something in between these two extremes as more realistic and potentially sufficient to meet the government's goals on CO2 reduction and security of supply, e.g., a middle scenario of 1,600MW in 2020 and 6,400MW (cumulative) in 2025, as per Ofgem's Project Discovery.

Similarly, electricity industry participants have made statements about their plans and ambitions to develop new nuclear capacity:

- EDF Energy has announced that it plans to develop 6,400MW (4 x 1,600MW) of new nuclear capacity for the UK market with the first plant operational by the end of 2017, and that it believes the UK market should have 15,000MW of new nuclear by 2030 (conditional on the government putting a floor under the UK CO2 price); [13]

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[11] Ofgem (2009), "Project Discovery – Energy Market Scenarios", Ref. 122/09, 9 October 2009, pp. 84-85.

[12] AEA Energy & Environment (2008), "MARKAL-MED model runs of long term carbon reduction targets in the UK – Phase 1", November 2008, p21.

[13] (1) EDF, "EDF Energy welcomes Energy National Policy Statements as ´defining moment´ on the road to secure, affordable and low carbon energy for UK consumers", press release, 11 November 2009;
(2) Platts Power in Europe, "ANALYSIS; UK nuclear new build – EDF Energy steps up CO2 demands", 13 July 2009. See also Platts Power in Europe, "ANALYSIS; UK nuclear – De Rivaz calls for carbon floor", 1 June 2009;
(3) EDF, "EDF Energy welcomes Conservative commitment to nuclear power and action on carbon price", press release, 19 March 2010;
(4) Platts Power in Europe, "Analysis; EDF buys British Energy – France leads UK nuclear charge", 6 October 2008.

- RWE/E.ON have announced they are jointly aiming to build 6,000MW of new nuclear plant for the UK market by 2025, with the first reactor online around 2020;[14] and
- SSE/Scottish Power/Suez have announced they are jointly aiming to build 3,600MW of new nuclear plant for the UK market, with construction on the first plant starting around 2015 (i.e., commissioning in the early 2020s).[15]

If these plans are implemented in full, 16,000MW of new nuclear capacity would be online by 2030, which is more than the 14,400MW by 2030 anticipated by the MARKAL modelling conducted for the CCC. This comparison casts doubt on whether the industry's plans can all be implemented simultaneously even in a scenario where the government adopts much more pro-active measures to promote new nuclear. Hence, we have assumed for our modelling that a maximum of 1,600MW of new nuclear can come online by 2020, with a further 4,800MW by 2025, and a further 8,600MW by 2030, taking the total potential new nuclear to 15,000MW by 2030.

We do not force our model to build this amount of new capacity. Instead we allow the model to choose the size and volume of new nuclear investment up to this cap based on assumptions about the costs and technical characteristics of a range of new generation technologies. In the locational scenario, we allow the model to develop new nuclear generation at all sites in England and Wales where developers have proposed new nuclear projects. In the uniform scenario, we allow the model to choose the quantity of new nuclear capacity that comes online, then we assume that this capacity comes online at those site where developers have announced the closest proposed online dates for new nuclear projects.

3.3.4. Carbon capture and storage

The government has committed to support a carbon capture and storage (CCS) demonstration programme on four power stations, and is holding a series of competitions to identify projects that will receive funding. In the first round of the competition, only the CCS retrofit project at Scottish Power's Longannet plant remains in contention,[16] so we assumed in our modelling that this project will be developed as planned.

In line with current government policy, we assumed that the three further demonstration projects will come online. However, as no announcements have yet been made regarding which projects are likely to be selected for funding, we had to define assumptions on which projects will be developed.

In December 2009, the European Union announced funding for six CCS demonstration projects. One of the plants to receive funding was a 900MW coal-fired power plant at

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[14] (1) RWE npower, "RWE npower, E.ON UK nuclear joint venture fully established", press release, 5 November 2009; (2) Platts Power in Europe, "PIE's New Plant Tracker – Europe on crest of CCGT wave", 24 August 2009.

[15] (1) SSE, "SSE, GDF SUEZ and Iberdrola to acquire site from Nuclear Decommissioning Authority", press release, 28 October 2009;
(2) Platts power in Europe, "Analysis: Scottish and Southern Energy – SSE fires warning shot across BE bows", 1 June 2009.

[16] Royal Society of Chemistry, "UK carbon capture a one horse race", 2 October 2010: http://www.rsc.org/chemistryworld/News/2010/October/22101001.asp

Hatfield.[17] On the basis that the Hatfield project has been awarded EU funding, we assumed that this project will go ahead as one of the planned demonstration projects.

In line with the UK government's recent decision to open the CCS demonstration competition to gas-fired generation capacity,[18] we assumed that the two further demonstration projects will be retrofits to existing CCGT capacity. On the assumption that these projects will be most economic if situated close to the Longannet and Hatfield projects so they can share transport and storage infrastructure, we assumed that CCGTs at Killingholme and Grangemouth will have CCS equipment retrofitted to some of their capacity.

In line with "level 1" of the CCS deployment assumed in the DECC Pathways document, we assumed that all four demonstration projects will be implemented before 2018, giving a total of 1.6GW of CCS demonstration capacity.[19] We allow our model to choose the extent of further CCS deployment after 2020, allowing it to develop new CCS capacity based on assumptions about the costs and technical characteristics of a range of new generation technologies.

3.4. Power Market Supply-Demand Fundamentals

3.4.1. Electricity demand

The starting point for our demand forecast is the total energy supply figure reported in the Digest of UK Energy Statistics for 2009 (378TWh) and subtract exports (3.7TWh). This procedure ensures that our model includes the total energy demand that needs to be met by generators connected to the GB transmission system and embedded within distribution networks, including losses.[20]

We rolled forward this energy consumption figure for the period until 2025 using the electricity demand growth rates forecast in DECC's "Updated Energy and Emissions Projections" (UEEP) document from June 2010.[21] We have taken these growth rates as the UEEP accounts for all government energy policies introduced prior to or as part of the July 2009 LCTP, as well as in the more recent Household Energy Management Strategy in March 2010. These projections also account for the expected impact of the Renewable Heat Incentive (RHI).

In the period after 2025, we assume that electricity demand will remain constant, reflecting the countervailing effects of energy efficiency improvements and economic growth, except for demand from heat pumps and electric vehicles. We assumed that the electricity demand

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[17] European Commission Press Release, 9 December 2009, *Selection of offshore wind and carbon capture and storage projects for the European Energy Programme for Recovery*

[18] Carbon Capture Journal, UK CCS competition open to gas projects, 8 November 2010: http://www.carboncapturejournal.com/displaynews.php?NewsID=678

[19] 2050 Pathways Analysis, DECC, July 2010, page 180.

[20] We also subtract 4.8TWh of pumped storage demand, as we model electricity supply and demand from these generators explicitly within our model.

[21] DECC, Updated Energy And Emissions Projections (URN 10D/510), June 2010.

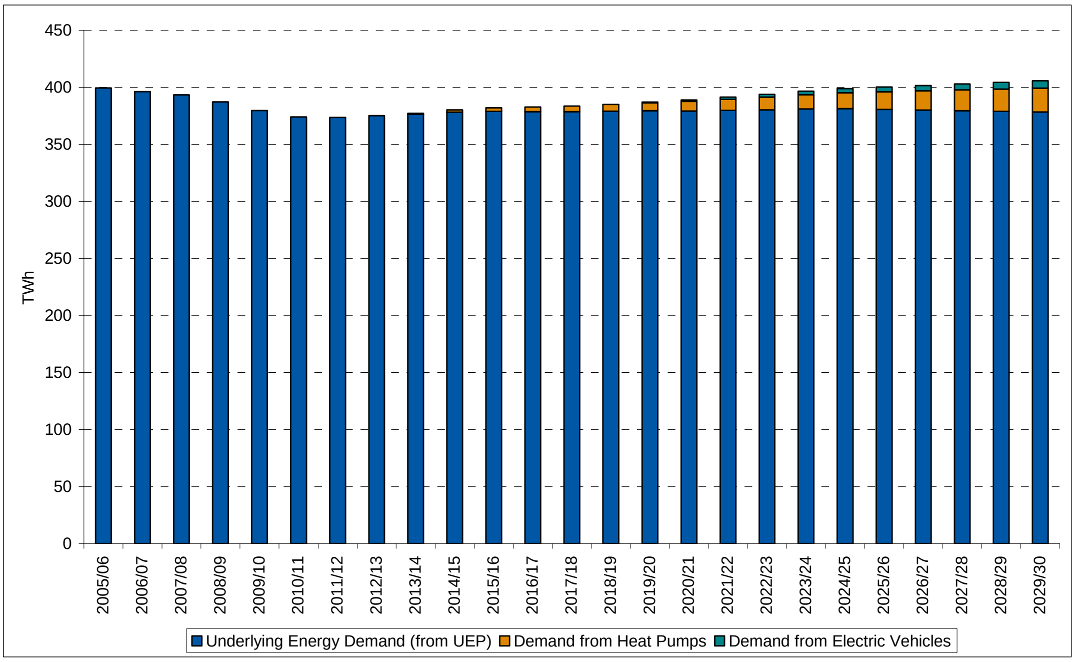
for space and water heating continues to grow reflecting the increased penetration of heat pumps.[22]

We shaped this energy demand forecast using outturn hourly electricity demand published by National Grid for 2009. However, we adjusted this demand shape over time for the changing contributions of electric vehicles and heat pumps to total energy demand.

As the UEEP does not account for the impact of electric vehicles on electricity demand, we also added additional demand from electric vehicles based on the penetration rates forecast until 2030 in the "mid-range" scenario in a study prepared for the Department of Business, Enterprise and Regulatory Reform (BERR) and the Department for Transport (DFT) in October 2008.[23]

Our overall energy and peak demand forecasts are shown in Figure 3.3 and Figure 3.4 respectively. Our peak demand forecast grows more quickly over the modelling horizon than our energy demand forecast due to the relatively large demand imposed by heat pumps at peak time.

Figure 3.3
Energy Demand Forecast to 2030 (TWh)



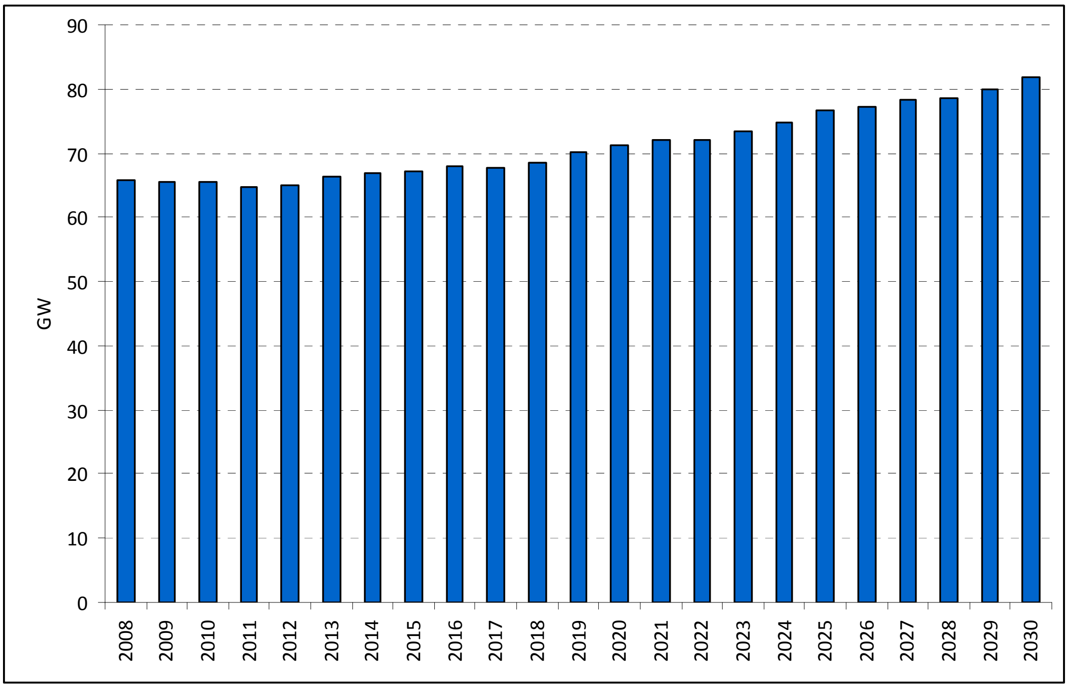
Source: NERA/Imperial analysis of data from various sources

22 Specifically, we assume that electricity demand from heat pumps reaches 8.4TWh, per annum based on assumptions in the Impact Assessment published on the RHI, and continues to grow to 22TWh by 2030.

DECC, Impact Assessment of the Renewable Heat Incentive scheme for consultation in January 2010 (URN 10D/547), 1 February 2010, page 27.

23 AEA Technology, Investigation into the Scope for the Transport Sector to Switch to Electric Vehicles and Plugin Hybrid Vehicles, October 2008, Section 2.5.

Figure 3.4
Peak Demand Forecast to 2030 (GW)



Source: NERA/Imperial analysis of data from various sources

3.4.2. Generation capacity

The starting point for our generation capacity assumptions is the list of transmission connected generation and distributed generation in National Grid's 2010 SYS.

In the limited number of cases where the SYS contains closure dates for existing fossil-fuel fired generators, we adopted these retirement dates for our market modelling. For all other existing fossil fuel fired generators, we allowed our model to select closure dates based on an assessment of each plant's profitability, subject to a maximum technical life:

- **Nuclear:** We assumed the existing nuclear fleet will retire two years after the dates published by the Nuclear Industry Association (NIA),[24] reflecting the life extensions planned by Wylfa and Oldbury compared to the NIA retirement schedule and an assumption that other nuclear plants will be granted similar life extensions.[25]

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24 Nuclear Industry Association Website, "UK nuclear power stations", 3 August 2006: http://www.niauk.org/uk-nuclear-statistics.html

25 The NIA retirement dates do not reflect the recent decisions by the Nuclear Decommissioning Authority to extend the retirement dates of Wylfa to 2012, and the expectation that Oldbury-on-Severn will operate until the end of 2010, and will run one of its two units until at least mid-2011. Sources: (1) Wylfa to continue generating until 2012, Nuclear Engineering International, 13 October 2010; (2) Magnox aims to run UK Oldbury reactor until mid-2012, Reuters News, 23 August 2010.

- **Coal:** We imposed a maximum asset lives of 55 years, based on the top-end of the distribution of retirement ages observed across a range of coal power stations in Europe.[26]
- **Other technologies:** We imposed maximum lives based on the economic lives estimated for power generators in a recent study by Mott MacDonald for the UK government.[27]

We also assumed that all new capacity that the SYS lists as under construction will come online at the dates National Grid assumes. However, we do not assume that any of the capacity listed as "consented" or "transmission contracted" will come online, and instead we let our model select the timing and location of all further generation investment.

3.4.3. Generators' response to the LCPD and IED

We assumed that all existing coal and oil-fired plants that have opted out of the Large Combustion Plants Directive (LCPD) will need to close by 31 December 2015, although we allow the model to close them earlier if it is not economic to keep them online until then.

We also accounted for the impact of the Industrial Emissions Directive (IED). We assumed that coal plants opting in to the IED will need to incur the cost of fitting Selective Catalytic Reduction (SCR) equipment to their whole capacity,[28] as well as conducting associated life extension works, *but* will be able to run without any load factor constraints throughout the period to 2030. Plants that opt out will not incur these costs, but will be limited to running 17,500 hours between 2016 and 2023. For modelling purposes, we assumed that each coal plant would allocate its available running hours evenly to each year between 2016 and 2023.[29]

Given this choice, our model endogenously selected whether each existing coal plant will opt in or out of the IED, with the following exceptions:

- We assumed that E.ON has committed to invest in SCR equipment for all units at Ratcliffe-on Soar, and so this unit will opt in to the IED;[30]
- We assumed that SSE will not invest in SCR equipment at Fiddlers Ferry, and opt the plant out of the IED, based on recent statements from the company.[31]

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[26] Based on data from Platts Powervision, we examined the distribution of the ages of coal plants that have previously retired. Our analysis suggests that 95% of those coal plants that have retired did so before they were 55 years old. On this basis, we imposed maximum asset lives of 55 years for GB coal plants. This assumption reflects the fact that the UK government will not allow like-for-like replacement of UK coal units, so there is no possibility of "economic replacement". Instead, we assumed it will be possible for UK coal units to operate as long as is technically possible. Hence, we tie our assumption on the maximum life of a GB coal plants to the top-end of the observed distribution of retirement ages.

[27] Source: Mott McDonald, UK Electricity Generation Costs Update, June 2010, Table 6.1.

[28] We understand that some plants face more choices, e.g. only fitting SCR to some units and not to others that share a common flue, but we ignore these options on the basis that we have insufficient knowledge from published sources of the compliance options available to individual coal plants.

[29] Our model does not allow us to optimise the use of the hours over multiple years.

[30] Design and manufacture of first SCR economisers in UK won by Ekstroms / A&J partnership, A&J Fabtech limited website, 12 January 2010. URL: http://www.ajfabtech.com/cgi-bin/ajf.cgi?Command=ShowNews&db_nid=62&SN=0

[31] Financial report for the six months to 30 September 2010, SSE, 10 November 2010.

The UK government's Impact Assessment for the IED assumed that retrofitting SCR in existing coal plants would cost £80/kW (real 2008).[32] However, we are not aware of any publically available estimates of the total cost of retrofitting SCR that includes the associated cost of life extension and refurbishment works, which we understand differ widely depending on the condition and configuration of each plant. Given this uncertainty, we have assumed that the total capex costs incurred by coal plants that opt into the IED is £180/kW.[33]

3.4.4. New entrant costs

To estimate the costs of developing and operating new greenfield generators (i.e. CCGTs, OCGTs nuclear and CCS) we used the upfront capital costs estimated in the Mott MacDonald (2010) "medium" case.[34]

As well as a menu of greenfield investment options, we also gave the model a limited number of brownfield investment options for CCGTs at sites where existing CCGTs already exist. We assume these options have the same cost as developing a greenfield site, but we subtract Mott McDonald's estimated capital costs associated with developing new infrastructure, which we assumed is already in place. We also assumed that the "regulatory, licensing and public enquiry costs" of developing a CCGT on an existing site are at the lowest end of the range estimated by Mott MacDonald for a new CCGT.

3.4.5. Fuel prices

Our method for forecasting commodity prices combines historic and forward market prices, quoted on 22 November 2010, and long-term commodity price assumptions published by DECC.[35] To forecast Brent crude oil, ARA coal and NBP gas prices until the end of 2013 (i.e. the liquid horizon of forward contracts), we use forward prices quoted by Bloomberg. We then interpolated to the longer-term fuel price assumptions published by DECC, which are consistent with the assumptions used by Mott MacDonald (2010) to estimate new entrant costs. The figures below present our fuel price forecasts.

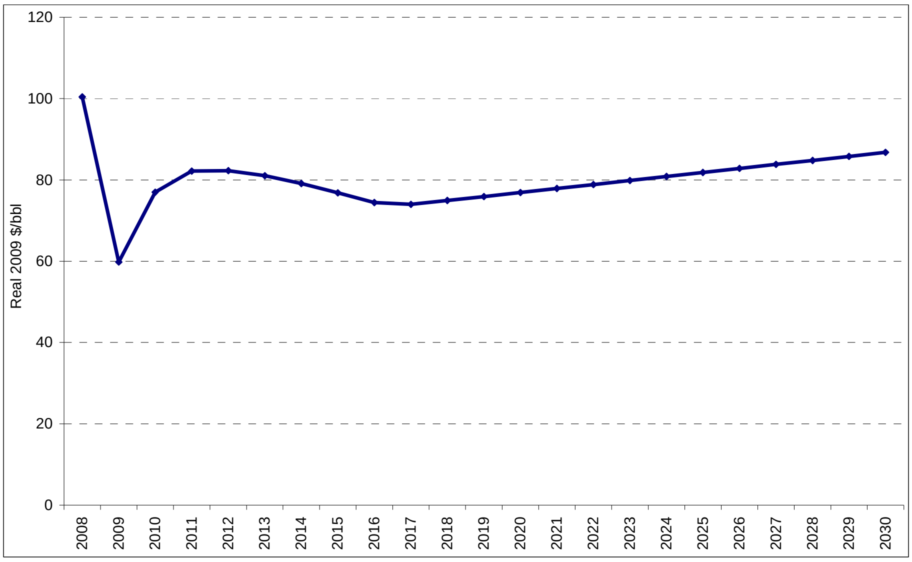
32 Source: Phase 1 of the Impact Assessment of the Proposals for a Revised IPPC Directive – Part 1: Combustion Plants – Final Report, May 2008, Defra.

33 We defined this assumption based on confidential industry sources.

34 Mott McDonald, UK Electricity Generation Costs Update, June 2010, Appendix A.

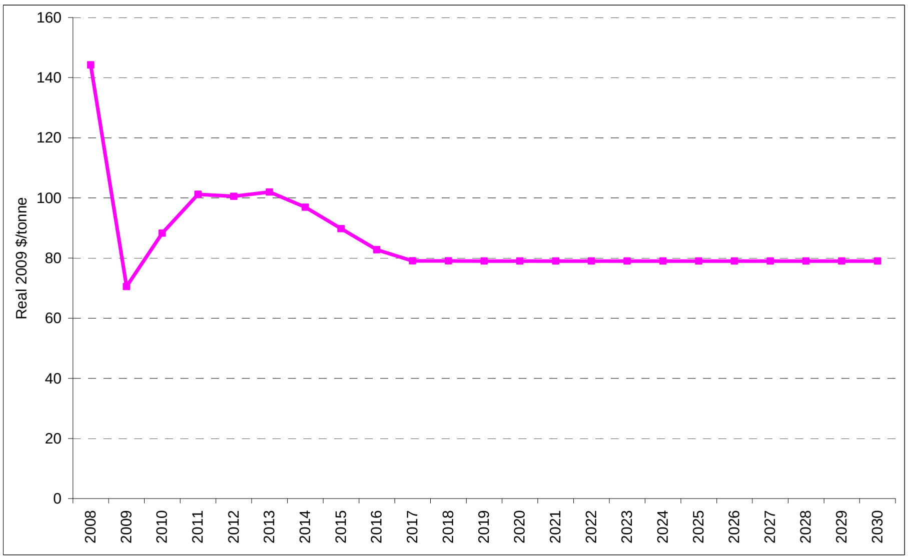
35 We used the "Mid Case - Timely Investment, Moderate"

Figure 3.5
Brent Crude Price Forecast (Real 2009 US$/bbl)



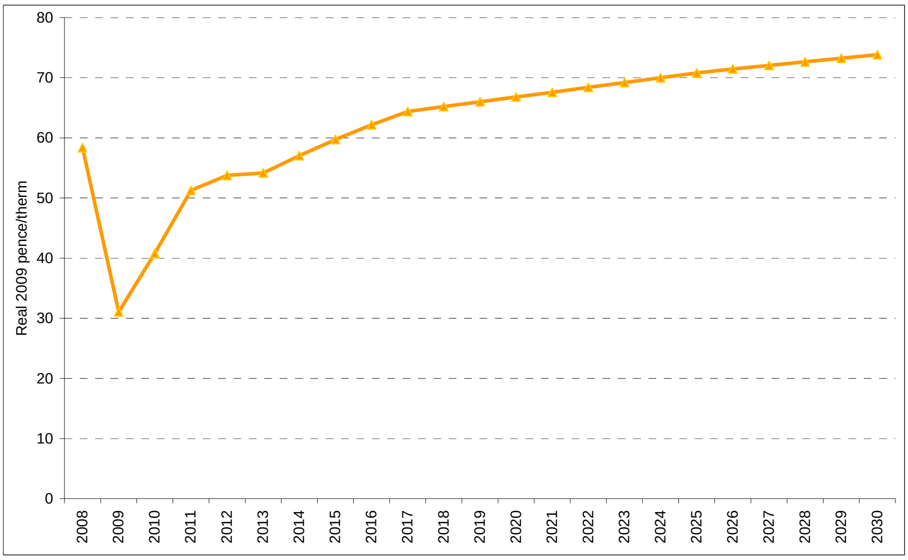
Source: NERA/Imperial Analysis of data from Bloomberg and DECC

Figure 3.6
ARA API#2 Price Forecast (Real 2009 US$/tonne)



Source: NERA/Imperial Analysis of data from Bloomberg and DECC

Figure 3.7
NBP Gas Price Forecast (Real 2009 pence/therm)



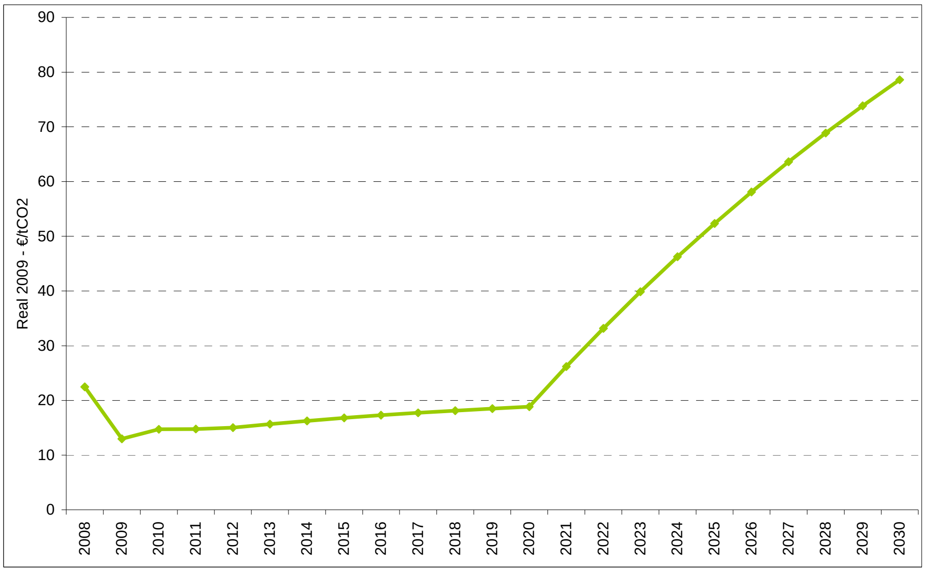
Source: NERA/Imperial Analysis of data from Bloomberg and DECC

3.4.6. The CO2 price

We used the same approach to forecast CO2 prices as we used to forecast oil, coal and gas prices, although Bloomberg only reported EU ETS forward prices until the end of 2012, so the interpolation to DECC's assumptions started one year earlier. As Figure 3.8 shows, our CO2 price forecast shows CO2 prices rising gradually until 2020, then rising rapidly between 2020 and 2030 reflecting government CO2 price projections published in 2010.

As described in Section 3.3, as well as our assumption that the RO provides support for up to 30% of renewables in power generation, we assume that the main policy mechanism for achieving government targets for emissions reduction in the power sector is the rising CO2 price shown below. Given this rising cost of CO2 emissions, we let our model choose patterns of generation dispatch and investment, and then examine the resulting emissions projections to see whether further increases in the CO2 prices will be required to achieve government aspirations.

Figure 3.8
CO2 Price Forecast (Real 2009 €/tonne)



Source: NERA/Imperial Analysis of data from Bloomberg and DECC

3.4.7. Generator technical characteristics

We describe in Appendix D our assumptions on generator technical characteristics, such as unit commitment costs, dynamic constraints, thermal efficiencies, outage rates and operating and maintenance costs. In general, our approach has been to rely on the Mott MacDonald (2010) study to define generation assumptions.[36] However, where necessary we have supplemented the data in this study with assumptions derived from data published on the BMRS (dynamic constraints), from our own analysis of historic emissions and power production data (thermal efficiencies), and other sources described in the appendix.

3.4.8. Renewables assumptions

We describe in Appendix E our assumptions on the costs of developing new renewable generation capacity, for defining caps on regional wind resource potential and for estimating the load factors achievable by wind generators in each region on GB. As for the generation assumptions, we relied on the Mott MacDonald (2010) study where possible, [37] but supplemented the data in this study with assumptions derived from other sources, as summarised in Table 3.1.

[36] Mott MacDonald, UK Electricity Generation Costs Update, June 2010.

[37] Mott MacDonald, UK Electricity Generation Costs Update, June 2010.

Table 3.1
Summary Sources Used for Wind Generation Assumptions

	Onshore	Offshore
Turbine and Tower Costs	Mott MacDonald (2010)	Mott MacDonald (2010)
Foundation Costs	N/A (Included in Mott McDonald)	Mott McDonald, plus adjustment for seabed depth of £9/kW/metre
Infrastructure Costs	T&D network charges modelled explicitly	T&D network charges modelled explicitly (incl. offshore local charges)
O&M Costs	Mott McDonald, plus land & business rates from Valuation Office Agency	Mott McDonald, plus business rates from Valuation Office Agency
Resource Caps	14GW by 2020 (Renewables UK) & 30GW by 2030 (DECC Pathways)	NG “Sustainable Growth” Scenario” from the Offshore Development Statement
Max Annual Build Rates	1GW/annum until 2020 rising to 1.6GW/annum thereafter based on DECC pathways & Renewables UK estimates	NG “Sustainable Growth” scenario from the Offshore Development Statement
Regional Load Factors	Analysis of wind speed vs. load factors by region (Carbon Trust / NERA analysis of DECC data)	Analysis of wind speed vs. load factors by region (Carbon Trust / NERA analysis of DECC data)

Source: NERA/Imperial Analysis

3.4.9. Interconnections with neighbouring markets

Our power market model covers both Great Britain and the Irish Single Electricity Market. Hence, we calculate flows across the existing Moyle and the planned East-West interconnectors endogenously within our market modelling framework.

We dispatch the interconnectors with France and the Netherlands within our market models based our assumptions regarding the marginal cost of generation in these markets. In France we assume that the market price overnight is set by the marginal cost of nuclear generation, and by the marginal cost of gas fired generation during the daytime. In the Netherlands, we assume that the market price is set by the marginal cost of gas-fired generators at all times.

For our transmission system modelling, we add hourly interconnector flows predicted by our market models, which may be positive or negative depending on the direction of flow, to hourly demand in the zones where the interconnectors connect to the British grid.

3.5. Transmission System Cost Assumptions

3.5.1. Transmission investment assumptions

DTIM has been used from National Grid as a validation tool for the proposed ENSG projects as well as for system operation modelling within the fundamental SQSS review. DTIM considers the main system boundaries, and we calibrated the transmission investment costs we assumed for these boundaries to reflect the costs of projects to increase boundary capacity proposed in reports from ENSG,[38] KEMA[39] and National Grid.[40]

[38] Our Electricity Transmission Network: A Vision for 2020, ENSG, July 2009

We calibrated our DTIM model by running our DTIM model using assumptions on reinforcement costs, generation capacity, demand and marginal costs from National Grid's "Gone Green" scenario, as presented in .

Finally, we included constraints on maximum boundary capacities, the most important of which is the maximum capacity of 4.4GW on the Cheviot boundary. In line with the assumptions adopted by National Grid we assume that any further increase in Scotland – England transmission capacity is delivered only through offshore DC links.

We defined assumptions on DC link costs from reports by ENSG and KEMA, and we assumed DC links with capacity between 1.8 and 2.2GW are feasible. In the Transport model DC links are modelled as 275/400kV cables, with the length adjusted to reflect DC link cost as quoted in ENSG report.

To estimate transmission investment costs, we used an average investment cost of £50/MW/km/yr, which is the lowest cost estimate that National Grid uses with the DTIM model.

By mapping the DTIM proposed transmission investment to actual projects considered in the ENSG report we were also able to change the network parameters of the Transport Model, where possible. For example, when DTIM invested in a boundary which corresponded to a line uprating, we changed the impendence of that boundary in the transport model.

We assume that new transmission infrastructure comes online as soon as our modelling suggests it is required. In reality, delays in commissioning new transmission lines (e.g. due to planning delays) may increase costs. Due to the higher requirement for new transmission investment in the uniform case, delays in developing new infrastructure would increase transmission system costs by more in the uniform than the locational scenario

3.5.2. Transmission constraint assumptions

DTIM selects optimal transmission investments by making a cost minimising trade-off between the costs of transmission investments and the costs of constraints. The costs of constraining generators down in one part of the country and constraining them up in another part of the country depends on the bids and offers they submit to the balancing mechanism.

For our modelling, we assumed that generators bid into the balancing mechanism at their short-run marginal cost of generation, ignoring unit commitment costs, dynamic constraints and the impact of market power which may result in spreads between their bid and offer prices. Because historically BM offer prices have been higher than short-run marginal costs and bids have been below short run marginal costs, this approach may tend to underestimate total constraint costs.

We set offer prices for nuclear and wind at high levels to because these technologies cannot be constrained on. Similarly, nuclear generation bid prices were set to a very negative

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[39] Assessment of the overall robustness of the transmission investment proposed for additional funding by the three GB electricity transmission owners, KEMA, December 2009

[40] Anticipatory Investment Update – 2010 , National Grid, 2010

number, so as to reflect the inflexibility of these plants and the high costs of constraining them down.

3.5.3. Transmission losses

The key focus of our analysis of losses is to assess the difference in losses in the two TNOuS scenarios, ie. uniform versus locational. Hence, the numerical values of losses presented in the rest of the report include (i) variable transmission losses in onshore transmission circuits, (ii) losses in Western and Eastern DC interconnectors and (ii) losses in offshore assets. The GSP transformer losses and losses in generator transformers are excluded as we made an assumption that these will be very similar in both uniform and location scenarios and will hence have no significant impact on losses between the two scenarios. However, given the higher investment profile in the uniform TNUoS scenario, this scenario will be accompanied with higher no-load related losses in various transmission assets (fixed losses in cables, corona losses, losses in compensation equipment etc). Given that we do not measure the increase in no-load losses (e.g., in overhead lines, cables and compensation equipment) associated with uniform TNUoS, we may have somewhat underestimated the difference in losses between the two scenarios.

For evaluating variable transmission losses in onshore transmission circuits under different transmission investment scenarios (associated with TNUoS scenarios), we first assess the equivalent boundary resistances as functions of boundary capacity and thickness (assuming that power transfers across the zones are security constrained). We then calibrated the resistances by considering the 2010/2011 annual losses from the SYS, which is around 2% of total energy demand (circa 6TWh). We recognise that this includes losses in GSP transformers in addition to fixed and variable losses in the transmission network, but excludes losses in generator transformers. Given that variable GSP transformer losses are demand dependant, we calculated an equivalent resistance of the transformers from Table 3.2. We have also estimated that generator fixed losses are around 65MW. We were then able to estimate the annual energy losses in transformers for 2010/11, which enabled us to compute the total transmission variable losses for 2010/11 and calibrate the DTIM boundary resistances. Given that our methodology for computing the boundary resistances is a function of boundary capacities (and thickness) but not a function of the number of circuits, this will lead to an underestimate of the difference in losses between uniform and locational TNUoS scenarios.

Table 3.2
Peak Demand Losses for 2010/11

Category	2010/11
Transmission Heating Losses excluding GSP Transformers (MW)	912.5
Fixed Losses (MW)	276
GSP Transformer Heating Losses (MW)	108.4
Generator Transformer Heating Losses (MW)	111
Total Losses	1,407.9
ACS Peak Demand (MW) excluding Losses and Station Demand	58,774
Total Losses as percentage of Demand	2.4

Source: National Grid Seven Year Statement

Losses in DC links and offshore transmission losses were computed based on the SEDG methodology[41] used for designing offshore transmission including DC circuits. Based on the capacity and expected power flows through the links, the transmission and converter / substation (both onshore and offshore) losses were computed for each offshore project including Western and Eastern bootstraps.

3.5.4. Offshore and island transmission costs

We used our own estimates for the offshore transmission costs for the different projects as laid out in our past report[42] complemented by the National Grid/Crown Estate report[43] for offshore round 3 projects. The costs were then transformed to a £/kW/year of generation capacity connected basis as summarised for each project in Table E.4 in Appendix E

For the island interconnectors and in particular the Shetland Islands and Western Isles links we assumed that the transmission capacities would be 600MW and 450MW and the annuitized costs equal to £85.2/kW/year and £61.1/kW/year respectively calculated from the ENSG report.

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[41] Cost Benefit Methodology for Optimal Design of Offshore Transmission Systems, Imperial College/SEDG, July 2008

[42] Grid Integration Options for Offshore Wind Farms, Imperial College/SEDG, December 2006

[43] Round 3 Offshore Wind Farm Connection Study, National Grid/Crown Estate, December 2008

4. Locational Scenario Modelling Results

4.1. Modelling Procedure

As we describe in Chapter 2, our modelling approach requires a process of iteration between our wholesale electricity market and transmission system models. We used our market models to predict the timing of incumbent generator closures, as well as the technology, timing and location of new generation investment given TNUoS charges. We used our transmission system models to predict transmission investment requirements and TNUoS charges, given the location and technologies of installed generation capacity. We conducted a series of iterations between the transmission and market models, continuing the process until we achieved reasonable convergence in TNUoS charges, which in practice required us to run eight iterations of our models.

4.2. Locational Investment Decisions

4.2.1. Development of TNUoS charges in the initial iterations

We started the process of iteration between the transmission and market models by assuming that existing TNUoS charges remain constant in real terms at their current levels until 2030 and then running our market models to forecast generation capacity over the modelling horizon. As we describe in Section 2.1, we put the resulting projections of generation capacity into the DTIM model, which we used to predict transmission investments, and then used these projections to forecast revised TNUoS charges using our charging model. We then put these revised TNUoS charges back into the market models to begin the next iteration, and continued iterating until we obtained reasonable stability in TNUoS charges.

Figure 4.1 shows the TNUoS charges that emerge from the first three steps of this iterative procedure. The figure shows that in both the second and third iterations, TNUoS charges in Scotland rise from their current levels to between £20 and £40 per kW per year in current prices. This growth in Scottish TNUoS charges occurs primarily through two "steps up" in charges, which coincide with the investments on the western and eastern HVDC links that our DTIM model predicts are required in 2014 and 2018 respectively. From the time when these investments are required, the marginal cost of reinforcing the grid to accommodate new generation in Scotland rises to reflect the cost of reinforcing the Cheviot boundary through offshore HVDC link(s) rather than through onshore AC network. This increasing marginal cost of reinforcement is reflected in rising TNUoS charges in Scotland.[44]

Figure 4.1 also shows that generation TNUoS charges in England and Wales fall, and in most cases become negative over the modelling horizon, because of the combination of the two

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[44] We compared TNUoS charges in Scotland obtained from our model with analysis carried out by National Grid as part of the ESNG process (see http://www.nationalgrid.com/NR/rdonlyres/4904BFDF-19C4-4C25-9354-70F958406F2A/39941/ENSGbootstrapsLSF084ENSG_final.pdf). We observe that TNUoS charges in Scotland increase from about £21/kW to about £28/kW after the western interconnector is installed in our modelling, while National Grid analysis suggests that the charges in Scotland will be above £30/kW. Our model suggests that the TNOuS charges in Scotland will further increase to about £38/kW after the eastern interconnector is installed, while National Grid suggests that charges in Scotland will reach about £45/kW. Hence, we conclude that our estimates are in a similar range to those of National Grid.

effects: (i) an investment in incremental generation capacity in England and Wales offsets the need for increased reinforcements in Scotland (including western and eastern HVDC links), and (ii) given that offshore network costs are largely covered by generators, generation TNUoS charges must be reduced by a fixed amount of approximately £4/kW across the system, in order to maintain the target split between generation and demand contributions to the total network costs.

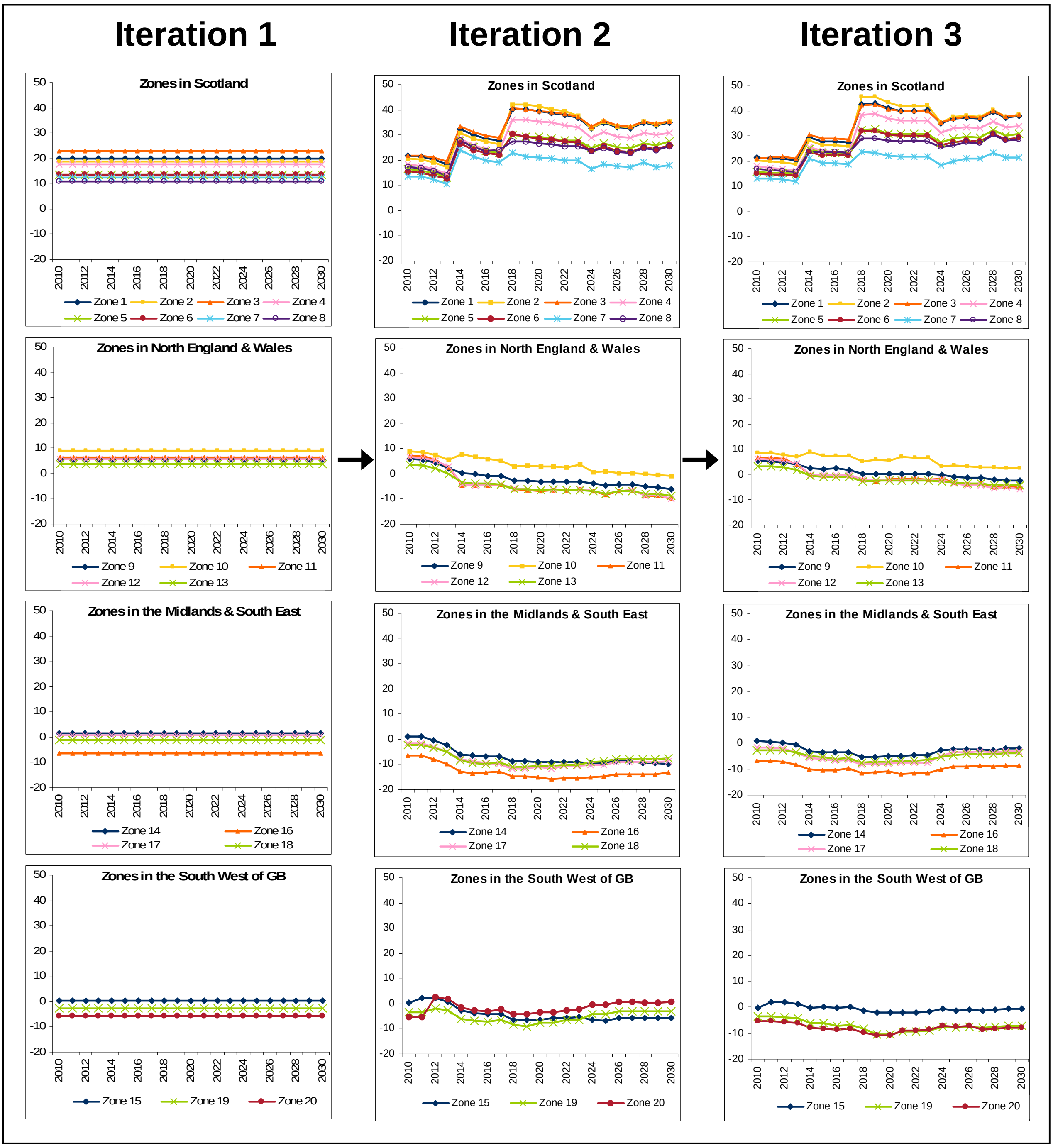
While the figure shows that tariffs in Scotland and the north of England and Wales are similar at iterations 2 and 3, there is some instability of tariffs in the south of GB, particularly between the south west and the south east. This instability occurs because in iteration 1 the model builds a large proportion of new OCGT and CCGT capacity in the south west of GB, which triggers substantial transmission reinforcements and hence increased TNUoS charges in this area of the country. At the next iteration, therefore, new investment in OCGT and CCGT capacity shifts away from the south west in response to increased TNUoS charges, locating closer to the south east of the country instead.

4.2.2. Convergence of TNUoS charges in the final iterations

In total, we conducted eight iterations of our market and transmission system models, and Figure 4.2 shows the TNUoS charges emerging from iterations 7 and 8, i.e. the final two stages of this iterative process. The similarity of charges in the north of Great Britain between the early iterations shown in Figure 4.1 and the final iterations shown in Figure 4.2 demonstrates that the model converged quickly to a stable locational spread of tariffs over GB as a whole.

However, as we saw in iterations 2 and 3, some instability in tariffs in the south of GB remained after the final iterations of the model, which again results from our market model relocating large amounts of OCGT and CCGT investment between the south west (iteration 7) and south east (iteration 8) in response to relatively small changes in TNUoS tariffs. In reality, as we explain further below, investment is likely to spread out across the south more than our model predicts (e.g., due to limitations on available sites), and hence a realistic scenario probably lies somewhere in between iteration 7 and iteration 8. As such, we stopped the iterations at iteration 8.

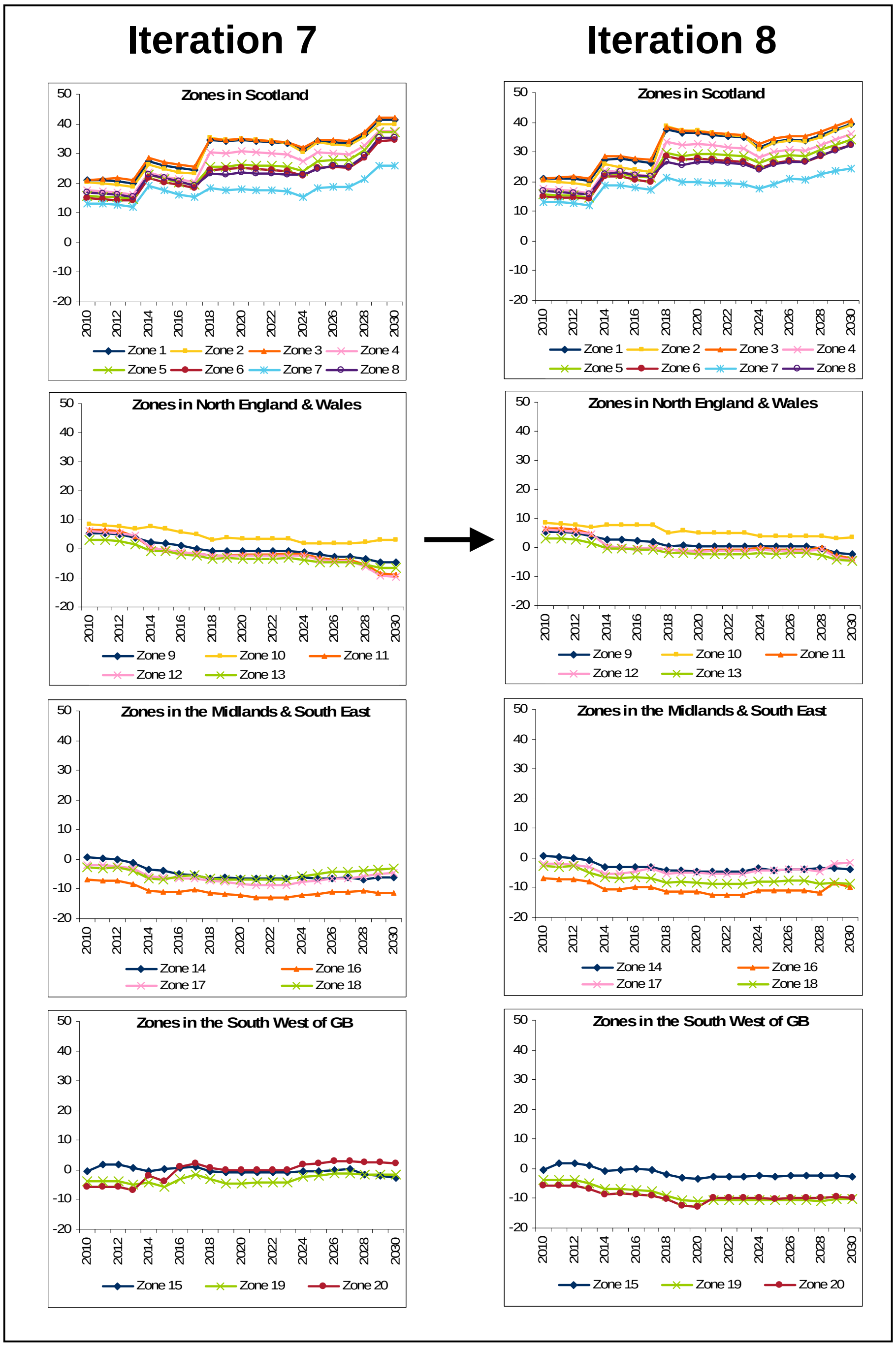
Figure 4.1
TNUoS Charges During Iterations 1-3 (Real 2010 £/kW/year)



Source: NERA/Imperial Analysis[45]

45 We present the generation and demand TNUoS charges arising from the final iteration in Appendix F.

Figure 4.2
TNUoS Charges During Iterations 7-8 (Real 2010 £/kW/year)



Source: NERA/Imperial Analysis[46]

4.2.3. Locational generation investment decisions

Figure 4.3 shows cumulative new generation investment by BMRS zone (see Figure 4.4 for mapping of BMRS zones to TNUoS charging zones[47]) and by technology in the final and

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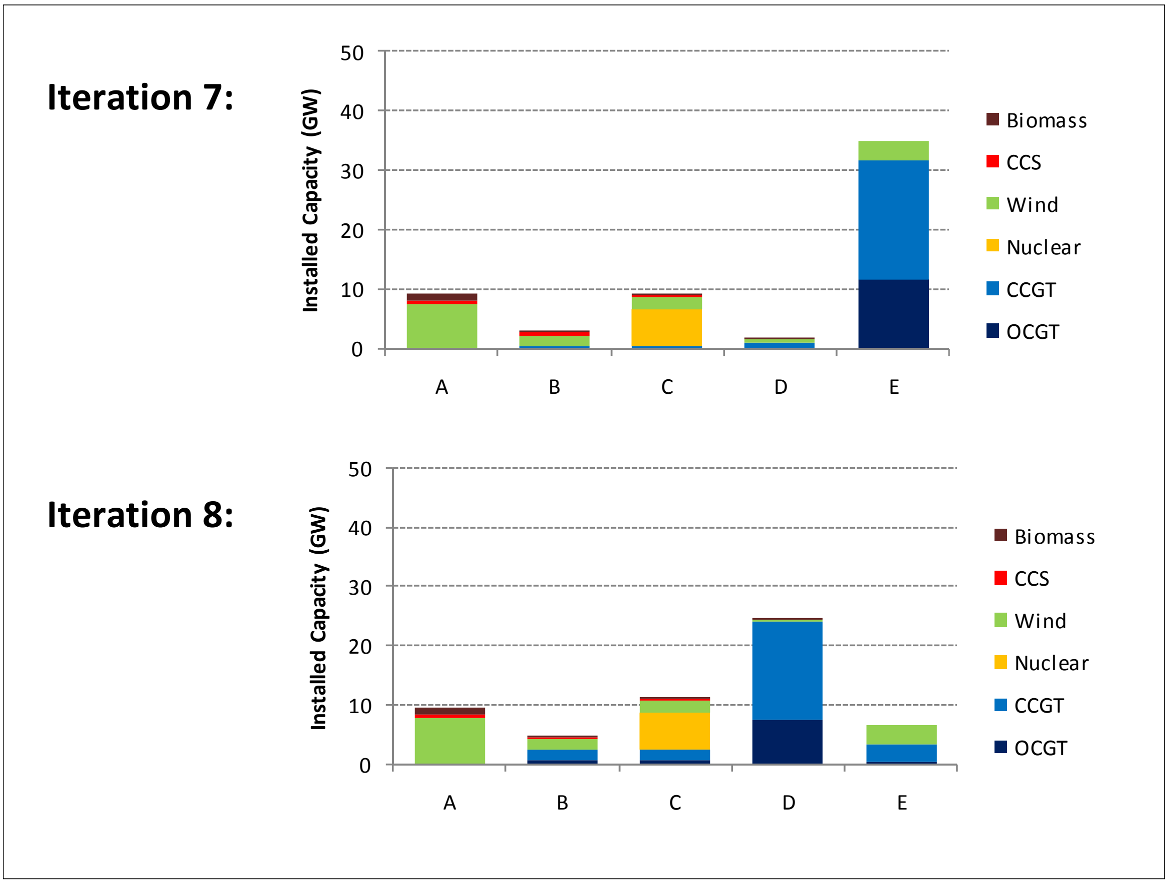
46 We present the generation and demand TNUoS charges arising from the final iteration in Appendix F.

penultimate iterations of the models. It shows that in both these runs, our model predicts the same quantity of new investment in wind capacity across all five zones. Hence, our model equilibrates on a stable projection of new wind investment, with capacity spread across the whole of GB, as we describe in more detail in Section 4.3.4 below.

The model also equilibrates to a stable projection of where new nuclear generation will be developed, choosing to construct new nuclear capacity in BMRS zone C at the Wylfa site. This decision reflects the falling TNUoS charges in the midlands and parts of Wales towards the end of the modelling horizon, as we show above in Figure 4.2.

Figure 4.3
Cumulative Investment in New Capacity to 2030 During Iterations 7-8 (GW)



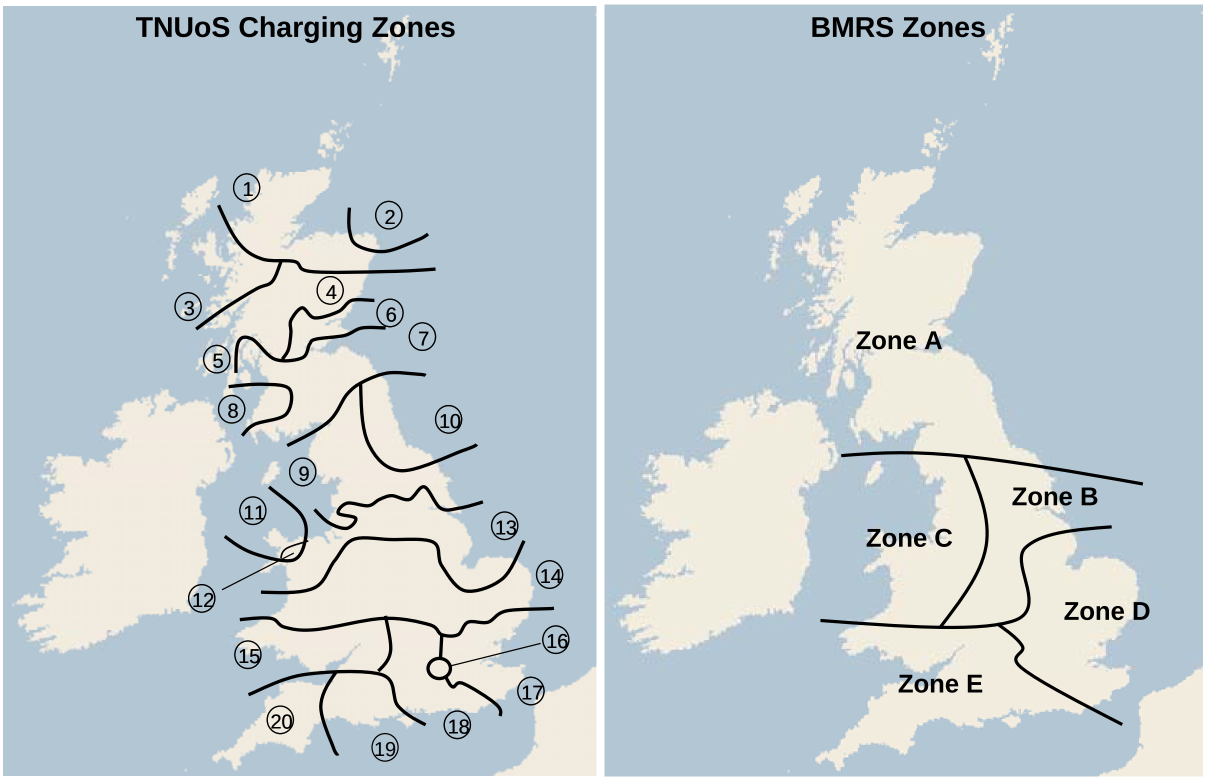
Source: NERA/Imperial Analysis

As we describe above, the main change between iterations 7 and 8 is that the location of new CCGT and OCGT investment predicted by the model shifts between the south west of GB in BMRS zone E at iteration 7, to a range of locations in the midlands, Wales and the south east (BMRS zones B, C, D and E) at iteration 8. Aside from having low TNUoS charges, the model selects these areas as they tend to be attractive for gas-fired generation due to their

[47] Although we model investment patterns at the level of TNUoS generation charging zones, for clarity of reporting we present generation investment patterns by the larger BMRS zones. We allocate the capacity of offshore wind developments to the zone in which they connect to the onshore grid.

proximity to National Transmission System (NTS) entry terminals, and hence their relatively low NTS exit capacity charges.

Figure 4.4
Illustration of TNUoS Charging and BMRS Zones



Source: BMRS Website

4.2.4. Transmission investment requirements

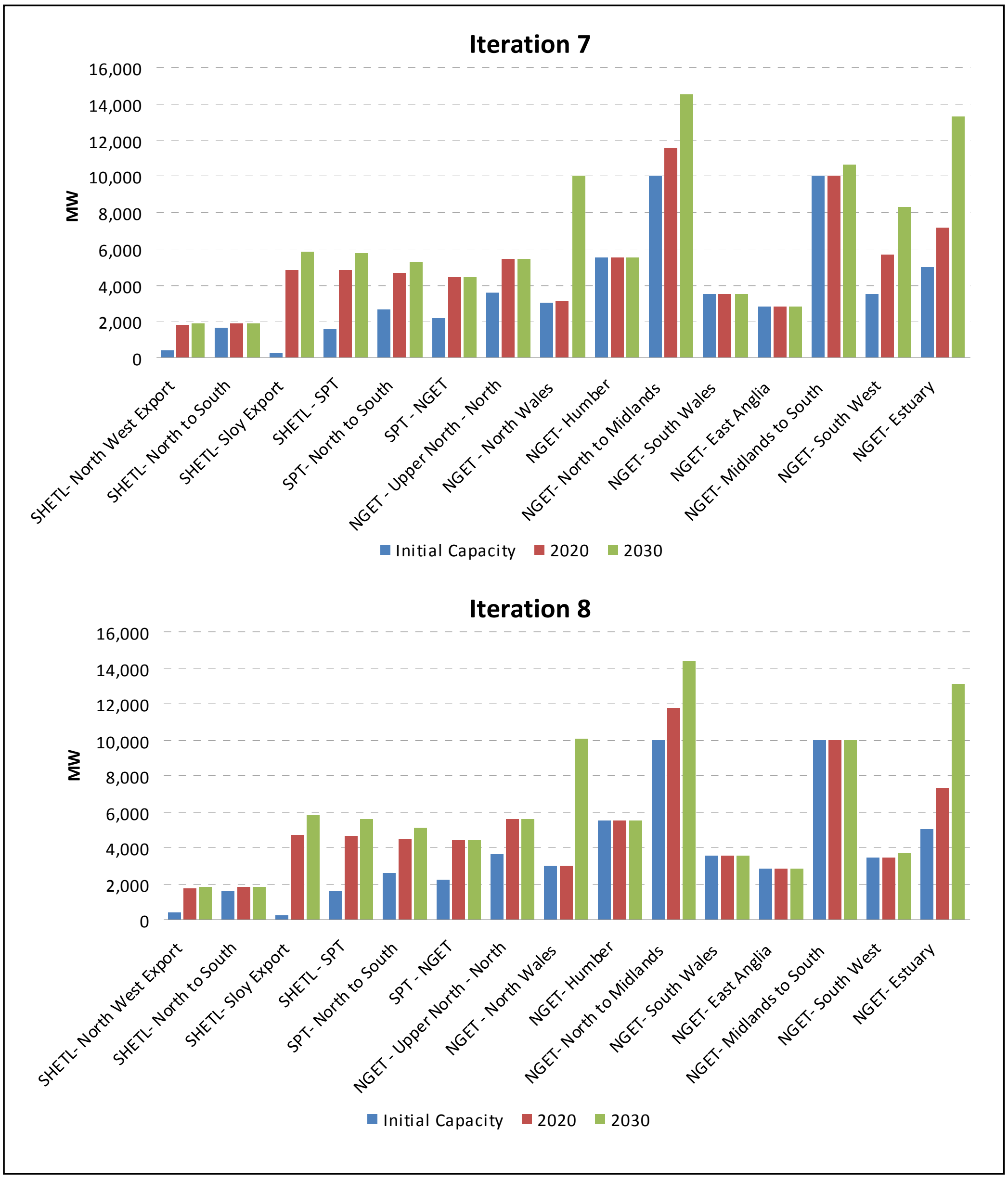
As Figure 4.5 shows, in both iterations 7 and 8, growth in renewables capacity in Scotland triggers substantial investment to reinforce the Cheviot boundary. Because we assume that onshore reinforcements to increase the capacity on this boundary are not feasible above 4.4GW, DTIM builds 1.8GW of capacity on the western HVDC link in 2014 connecting the SPT- South area to North Wales, and 1.8GW of capacity on the Eastern HVDC link in 2018, which connects SHETL-North to NGET-Upper North. Also, at both iterations 7 and 8, investment on the North Wales boundary during 2020-2030 takes place because new nuclear capacity is commissioned in this area.

At both the 7th and 8th iterations, transmission investment is triggered on the North Wales and North to Midlands boundaries to transfer power to the southern load centres, due to the HVDC injections in North Wales and NGET-Upper North, the new nuclear in north Wales, and the new renewable capacity in BMRS zones B and C. DTIM also predicts that some investment will be required on the Midlands to South boundary.

However, in the south of Great Britain, there are differences between the investment patterns predicted by DTIM in iterations 7 and 8. In iteration 7, the development of new OCGT and CCGT capacity in the south west of GB requires substantial investments on the NGET-South

West boundary. In contrast, in iteration 8, there is less investment in the NGET – South West boundary, since the majority of the new conventional capacity is developed in the south east and (to some extent) the midlands. This change increases transmission investment requirements on the NGET – Estuary boundary.

Figure 4.5
Transmission Investment by DTIM Boundary: Iterations 7-8



Source: NERA/Imperial Analysis

4.2.5. Implications for welfare analysis

As described above, our iterative modelling procedure results in stable projections of the timing, quantity and location of new generation capacity, and transmission reinforcements and TNUoS charges in most parts of the country. In particular, our modelling clearly shows that it is optimal for new conventional generation to locate in the south of GB with locational TNUoS charges, rather than in the north of England or Scotland. The only material differences between the final and penultimate iterations occur because our market model relocates large amounts of OCGT and CCGT capacity between the south-west and the south-east in response to relatively small changes in TNUoS charges.

These shifts in the location of OCGT and CCGT capacity arise because our wholesale market modelling framework locates investment where our underlying cost assumptions suggest it will be most profitable however small the differences in profitability, and taking our estimates of TNUoS charges as given from one iteration to the next. In reality:

- factors that we have not taken into account in our modelling due to a lack of objective data are likely to affect locational decisions, such as:
  - the limited availability of suitable sites for developing new generators in a particular region (e.g., due to constraints imposed by the planning regime or the availability of cooling water);
  - the fact that National Grid re-zones each year in response to changing nodal marginal costs, which might smooth out some of the shifts in charges that our model forecasts;
- investors adjust their expectations of TNUoS charges dynamically in response to investment trends, and hence they do not assume TNUoS charges are fixed independent of the amount of investment going into a zone as our model does within a single iteration.

These factors will tend to lead to a wider geographic dispersion of new conventional generators across the south than our modelling suggests. We conclude that a realistic scenario therefore lies somewhere in between iteration 7 and iteration 8, and hence we have taken an average of the transmission costs in these two iterations for the purpose of the welfare analysis described in Chapter 6.

4.3. Market Modelling Results

This section presents high-level summary market results from iteration 8, covering our projections of the supply-demand balance in the GB wholesale electricity market, wholesale prices, and the pattern of new wind investment. In practice, although our results exhibited some instability in the location of new CCGT and OCGT investments in the final iterations of the modelling, the high-level summary results presented here do not differ across iterations 7 and 8.

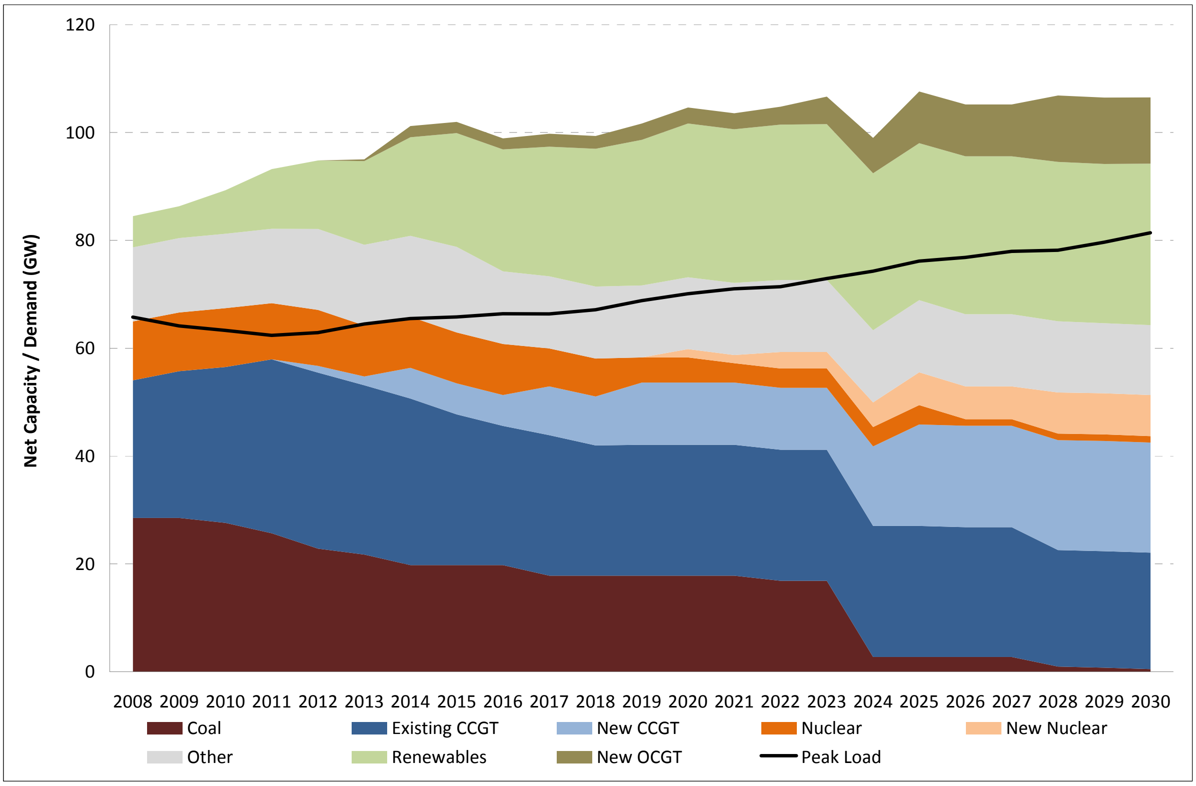
4.3.1. Supply-demand balance in the wholesale power market

Figure 4.6 shows our projection of installed generation capacity and peak load in the British power market. It shows that installed capacity currently stands at around 90GW comprising predominantly gas-fired CCGTs, steam coal and nuclear plants.

The chart shows that the 9GW of existing coal-fired generators that have opted out of the LCPD close gradually over the period to 2015, and that the majority of other coal plants close around 2023 having opted-out of the IED. The model's decision to opt the majority of coal plants out of the IED is driven by the rapid growth in CO2 prices post-2020, and the cost of retrofitting SCR equipment (see Sections 3.4.3 and 3.4.5). Existing nuclear stations also close gradually, in line with the assumptions on closure dates we defined from the NIA's projections.

Going forward, our assumption that the UK achieves 30% of renewables in power generation by 2020 means installed renewables capacity (including hydro) grows from around 8GW at the start of 2011 to around 30GW by 2020. In addition to this renewable investment, our model predicts investment in new CCGT capacity from around 2014, and in new OCGT capacity to provide peaking supply from 2016. The model also predicts some investment in new nuclear capacity, reaching a total of 6GW by the end of our modelling horizon in 2030. Hence, the model chooses to build less new nuclear capacity than the caps we defined, which would have allowed 14.4GW of new nuclear capacity by 2030.

Figure 4.6
GB Peak Load and Installed Capacity by Technology (GW)

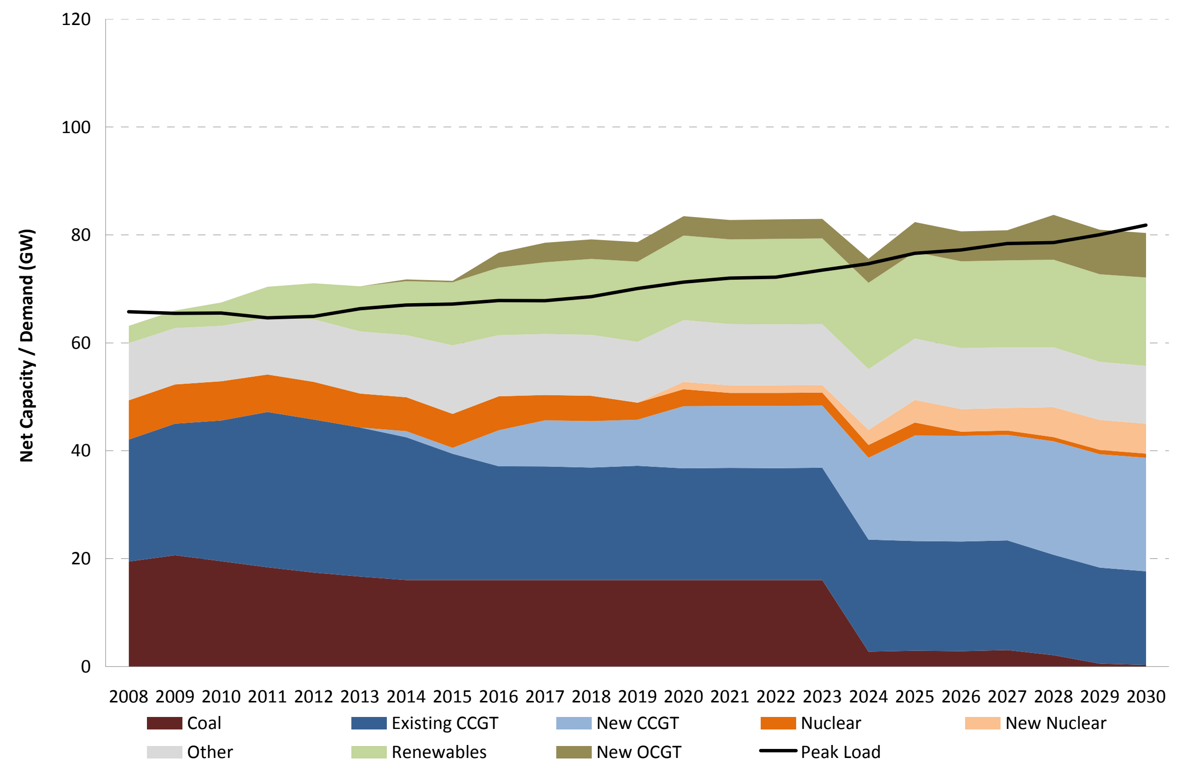


Source: NERA/Imperial Analysis[48]

Figure 4.7 shows the same picture, although with installed capacity derated for average availability at the time of peak demand. It shows that the model converges on an 8% reserve margin of available capacity over peak load between 2020 and 2030.

48 We present in Appendix G the forecast capacity and demand data behind this chart.

Figure 4.7
GB Peak Load and Derated Capacity by Technology (GW)



Source: NERA/Imperial Analysis

Figure 4.8 shows the modelled evolution of production from each technology over the modelling horizon. It shows that approximately 37% of production currently comes from gas-fired CCGTs, with 27% and 16% from coal-fired and nuclear generators respectively. A mix of renewables, oil-fired units and imports make up the remainder of production from British generators. Until 2015, Figure 4.8 shows that the share of production from gas fired generators falls as the share of renewables in the generation mix increases. At the same time, the share of output from existing coal and nuclear generators remains relatively stable. From 2016, the majority of existing coal plants that opt out of the IED accept 17,500 limited operating hours that we assumed they spread evenly between the years 2016-23.[49] Hence, production from coal plants falls in 2016 and again in 2023 when opted out coal plants close.

By 2020, the share of renewables in power generation reaches 30% and remains at that level until 2030. New gas-fired CCGT capacity accounts for an increasing share of the generation mix, meeting the share of demand growth not met by new renewables and nuclear. The quantity of production from existing CCGTs remains relatively stable between 2016 and 2030.

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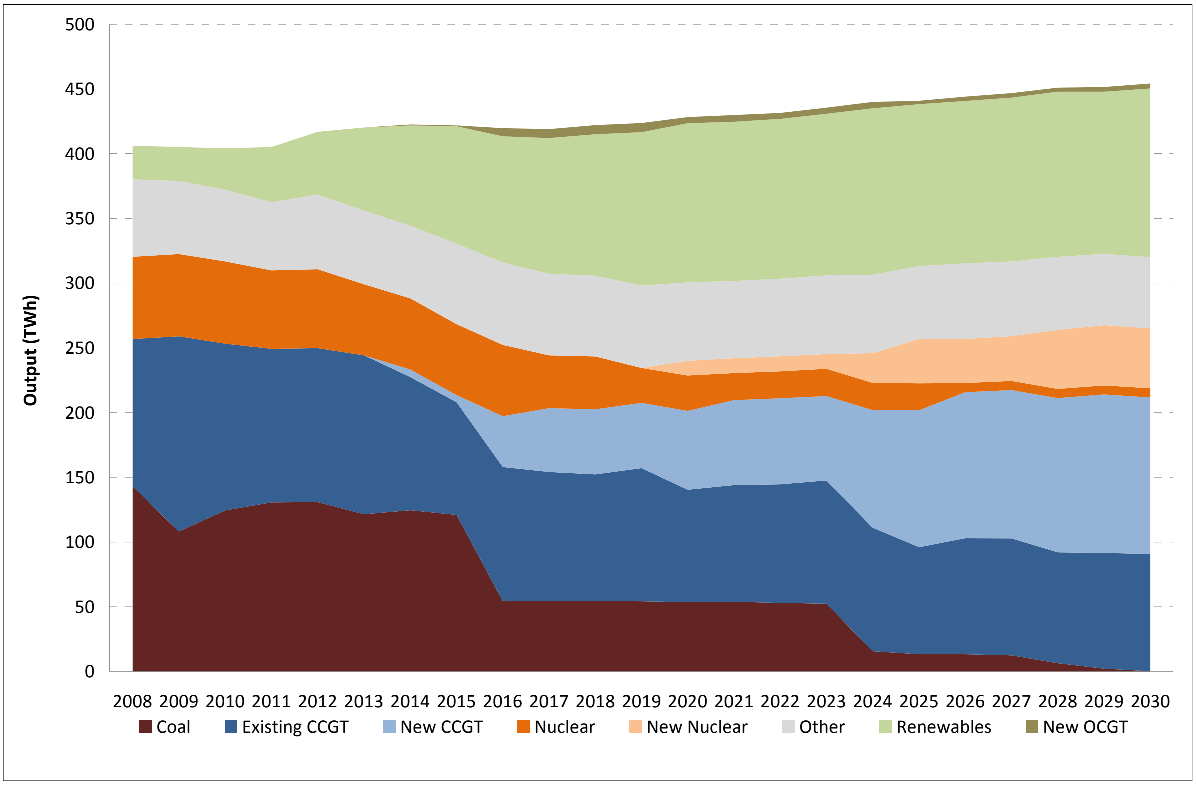
49 We profiled the running hours of opted out coal plants based on the patterns of production at those coal plants that have opted out of the LCPD since the start of 2008 using "indicated generation" data from the BMRS.

Figure 4.8
Generation Output by Technology (TWh)



Source: NERA/Imperial Analysis

Our model suggests that in the long-run the market converges on an equilibrium where sufficient generation and import capacity is available to meet peak load. However, in the long-run there remains a trade-off between the construction of peaking plant and the value of lost load, which is the level to which prices spike when there is insufficient capacity to meet demand and the model needs conduct involuntary load shedding.[50] Figure 4.9 shows the percentage of energy demand that our model predicts will be shed over the period to 2030 due to instances of insufficient generation capacity. It shows that, on average, the model sheds less than 0.02% of energy demand involuntarily throughout the period between 2020 and 2030, although the lumpiness of generation investments means that this figure is volatile from year-to-year. For example, we allow the model to construct greenfield gas-fired CCGTs in units of 800MW, so the model will sometimes delay investment in new plants until these relatively large units become profitable, causing short-lived increases in the quantity of load that the model sheds, e.g. in 2019 and 2030.

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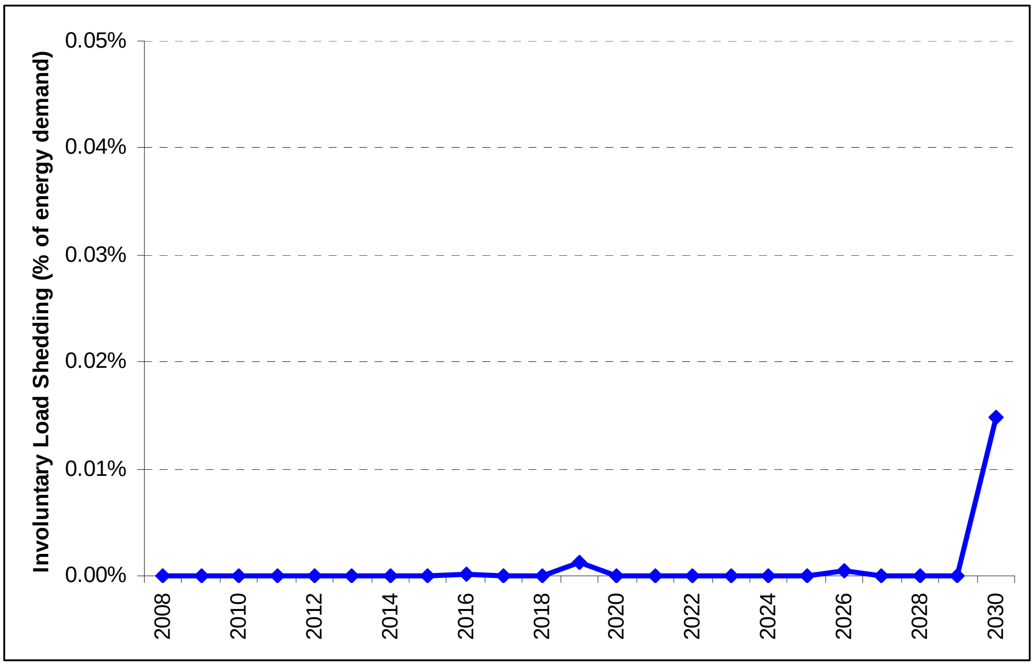
[50] In practice, we allow our model to shed a small amount of load to reflect the elasticity of some users' demand to high prices. We assume that at present approximately 1GW of load can be shed voluntarily at times of high prices (up to €300/MWh). We increase the quantity of "voluntary" demand response by 2.8% of peak load over the period to 2020 to account for the planned deployment of smart meters to all consumers. However, if the model needs to conduct further "involuntary" load shedding, we assume that prices would need to rise to the value of lost load (€10,000/MWh).

We assume smart meters provide additional demand response equal to 2.8% of peak load based on the assumption in the DECC Impact Assessment on the roll out of smart meters to the domestic sector that smart meters will reduce peak load by 2.8%. Source: DECC, Impact assessment of a GB-wide smart meter roll out for the domestic sector, May 2009, page 19.

Figure 4.9
Annual Involuntary Load Shedding (GWh)



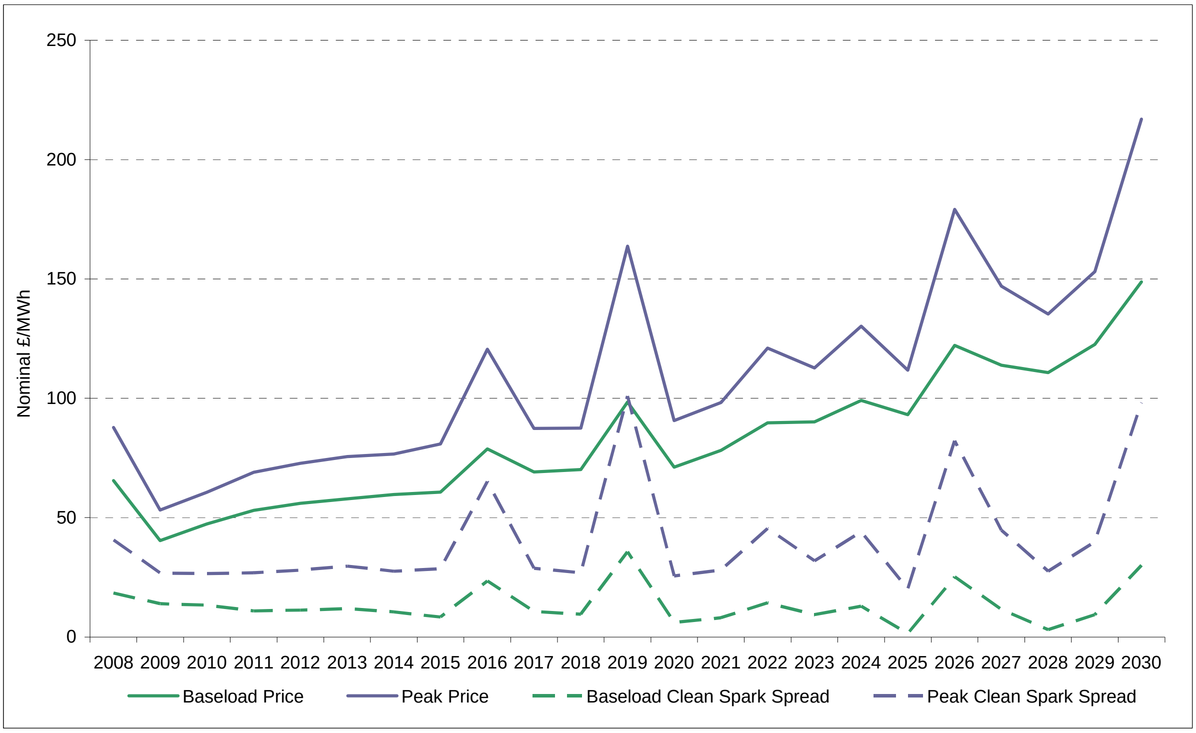
Source: NERA/Imperial Analysis

4.3.2. Wholesale power prices

Figure 4.10 shows our forecast of baseload and peak wholesale power prices in the locational scenario. It shows that power prices rise throughout our modelling horizon in line with the assumed growth in commodity prices. However, baseload clean spark spreads fall gradually over the period to 2015, due to increasing renewables capacity, until the market tightens in 2016 due to the retirement of the coal plants opted out of the LCPD, and reflecting the model's decision to build around 8GW of new CCGTs between 2015 and 2017. Thereafter, peak clean spark spreads trend upwards while baseload clean spark spreads exhibit no upward or downward trend, albeit they show some year-to-year volatility due to the lumpiness of investment.

This increase in peak/off-peak spreads results from the increasing penetration of renewables (especially wind) on the system. Higher renewables penetration increases the frequency of prices below the short-run marginal cost of gas-fired CCGT plants, which coincides with increasing scarcity in the market that causes prices to rise more frequently to the short-run marginal cost of gas-fired OCGTs and other peaking plants, or to the value of lost load.

Figure 4.10
Wholesale Power Prices and Clean Spark Spreads (Nominal £/MWh)



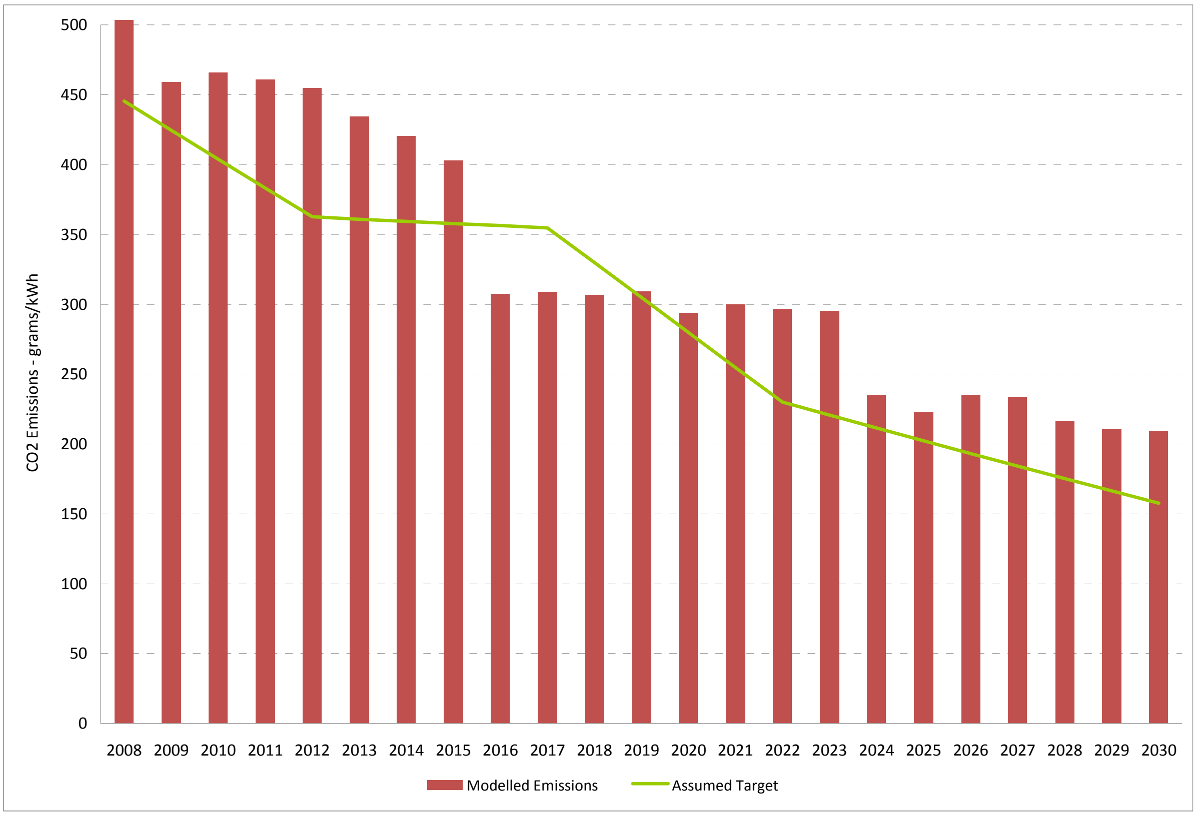
Source: NERA/Imperial Analysis

4.3.3. Emissions projections

Figure 4.11 shows our projection of power sector CO2 emissions, which reach around 200 grams/kWh by 2030, which as we discuss in Section 3.3.1, is close to the target trajectory required to decarbonise the UK power sector by 2050, and close to the "baseline" in the EMR consultation document.

Because our wholesale market model does not allow us to impose annual emissions constraints, we planned to impose the CO2 emissions target shown in Figure 4.11 by increasing the long-term CO2 price used for our modelling. In practice, however, we did not need to adjust the DECC long-term CO2 price forecast described in Section 3.4.5. Given the uncertainty regarding the speed and extent of CO2 emissions required in the UK power sector, we concluded that our emissions projections are sufficiently close to our assumed target not to require a further round of modelling with an increased long-term CO2 price.

Figure 4.11
CO2 Emissions vs. Assumed Target (grams per kWh)



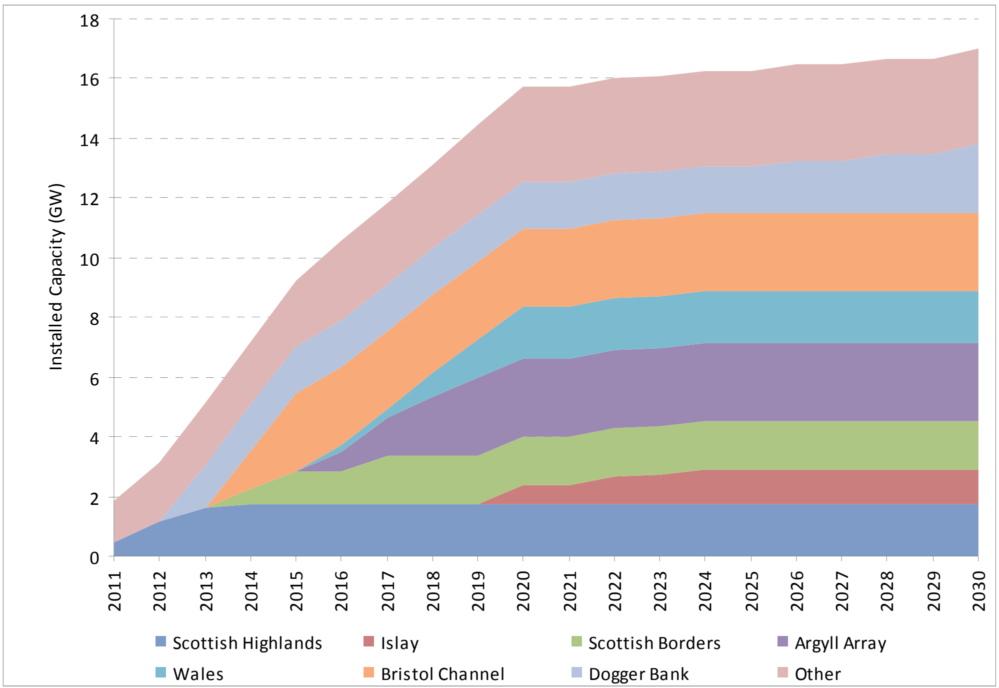
Source: NERA/Imperial Analysis

4.3.4. Patterns of renewables investment

As described in Section 2.2.1, we developed a renewables investment model to predict the volume and location of new wind investment in GB throughout our modelling horizon. Figure 4.12 shows that our model predicts investment in a wind range of new wind sites, the largest of which are labelled on the chart.[51]

[51] Figure 4.12 and Figure 4.13 only show the new investment predicted by our model. It excludes the projects listed in the SYS as under construction that we assume come online as planned. Note that we did not impose a lead time constraint in our modelled reflecting an assumption that wind projects are in development across many areas of the country, and could begin construction within the next 12 months if developers choose to go ahead with the project. Hence, our model predicts new investment from 2011. If we were to impose a lead time assumption on new wind projects, this would tend to shift back the profile of new investment predicted by our model, and would necessitate a faster average build rate until 2020 to meet the 30% target. However, we do not envisage that the overall mix of projects selected by our model would change materially.

Figure 4.12
Wind Investment Patterns (GW) – Major Projects & Areas of Wind Development



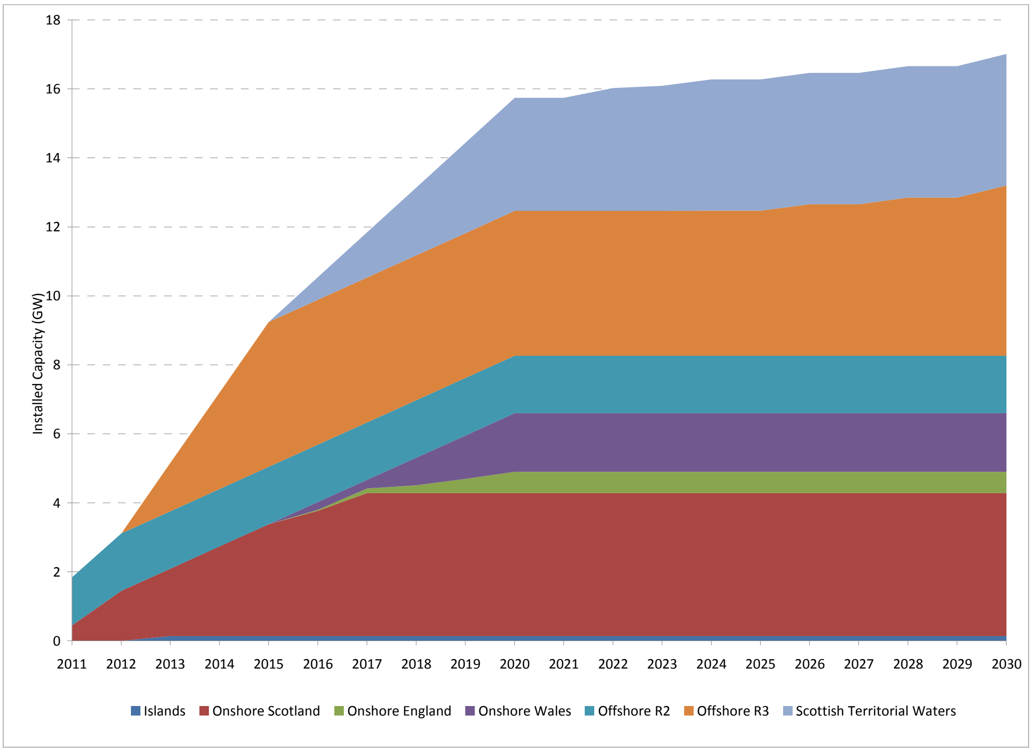
Source: NERA/Imperial Analysis

Figure 4.13 shows the same projection of wind capacity, but using a different aggregation of sites. The figures show that the majority of new onshore capacity is developed in Scotland, with installed capacity of 4.3GW by 2020, of which around 140MW is developed on the Scottish islands (Shetland and the Western Isles). The model also predicts development of around 1.7GW of onshore wind capacity in Wales by 2020, compared to around 0.6GW of onshore capacity in England. The model chooses to develop onshore wind in Scotland before it develops onshore wind in England and Wales due to the high load factors achievable at some Scottish sites. As the model exhausts the available sites with high load factors, and as increasing north-south power flows raises TNUoS charges in Scotland relative to those in England and Wales, the model starts to develop onshore sites in England and Wales.

Offshore, the model develops round 2 (R2) sites as soon as possible, reflecting the relatively low capital costs of these projects compared to those located further offshore. It then begins to develop round 3 (R3) sites, which we assume are available from 2013. It develops sites in Scottish Territorial Waters (STW) from 2016. The model continues to develop R3 and STW offshore sites throughout the modelling horizon.

The model develops a range of R2 sites, but selects only a limited number of R3 and STW sites for development, focussing on the Dogger Bank, the Bristol Channel, Islay and the Argyll Array. This limited number of developments reflects the model's decision to select only the most profitable sites, based on the cost and load factor assumptions we defined (see Appendix E).

Figure 4.13
Wind Investment Patterns (GW) – Aggregated Areas



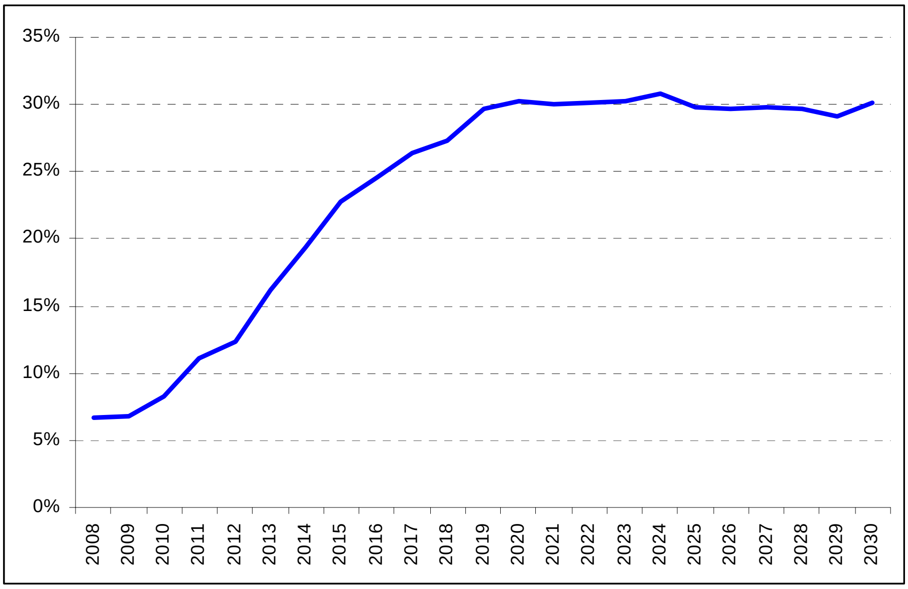
Source: NERA/Imperial Analysis

The relatively smooth rate of new wind development predicted by our model in the period to 2020 (see Figure 4.12 and Figure 4.13) illustrates that the constraints we impose on the annual build rates for new wind capacity are binding.[52] Hence, the model is building as much new wind capacity as we assume it can build, and is doing so as soon as possible. As Figure 4.14 shows, our modelling results indicate that the 2020 target of 30% renewables in power generation is met on time.[53]

52 We assume build rate caps of 1GW per annum onshore and 1.6GW per annum for offshore

53 In fact, the 30% target is exceeded in some years. This results from the sampling procedure adopted by our wholesale market model that means the constrain we impose in the renewables investment model may not match exactly the share of renewables generation

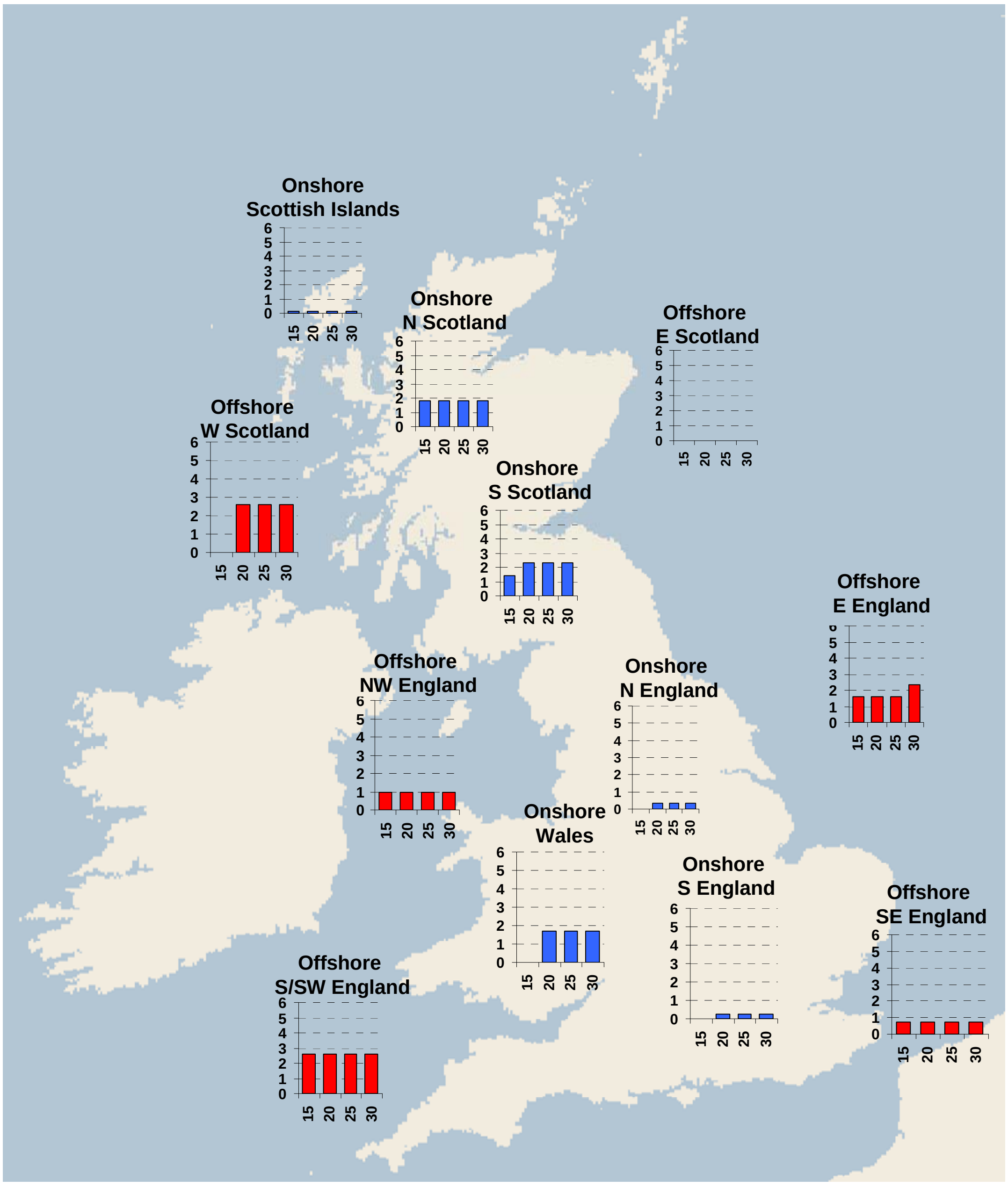
Figure 4.14
Share of Renewables in Power Generation (%)



Source: NERA/Imperial Analysis

Figure 4.15 presents the same wind capacity projections as in Figure 4.12 and Figure 4.13, but illustrating the regional distribution of new wind investment predicted by our model using bar charts showing capacity at five-year intervals between 2015 and 2030.

Figure 4.15
Map of Regional Wind Investment Patterns



Source: NERA/Imperial Analysis

4.4. Transmission System Modelling Results

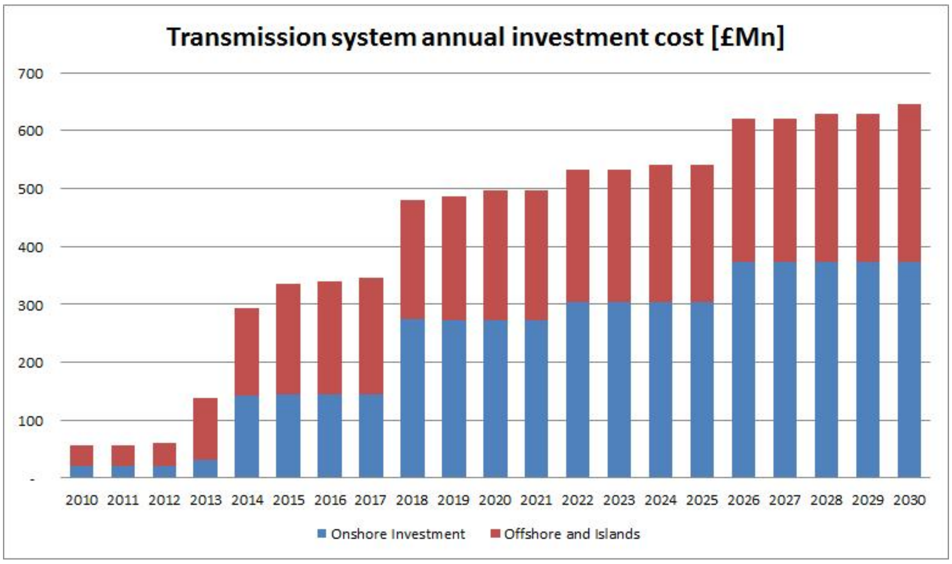
Given the range of locational investment decisions projected in iterations 7 and 8 of our modelling procedure, this section presents estimates of transmission system costs for both these runs of the model.

4.4.1. Investment costs

Figure 4.16 and Figure 4.17 present the cumulative annualised cost of new transmission investment, which includes the cost of onshore re-inforcements, the HVDC links and the new offshore and island transmission assets. For simplicity, we annuitise these costs taking into account the lifetime of the transmission lines and National Grid's required rate of return. (Accounting costs will follw a different profile.) The figure shows that a significant portion of the projected onshore re-inforcement costs occur in 2014 and 2018, which is due to the commissioning of the DC bootstraps, while the costs of offshore and island connections rise gradually throughout the modelling period, accounting for around half of the investment costs by 2030.

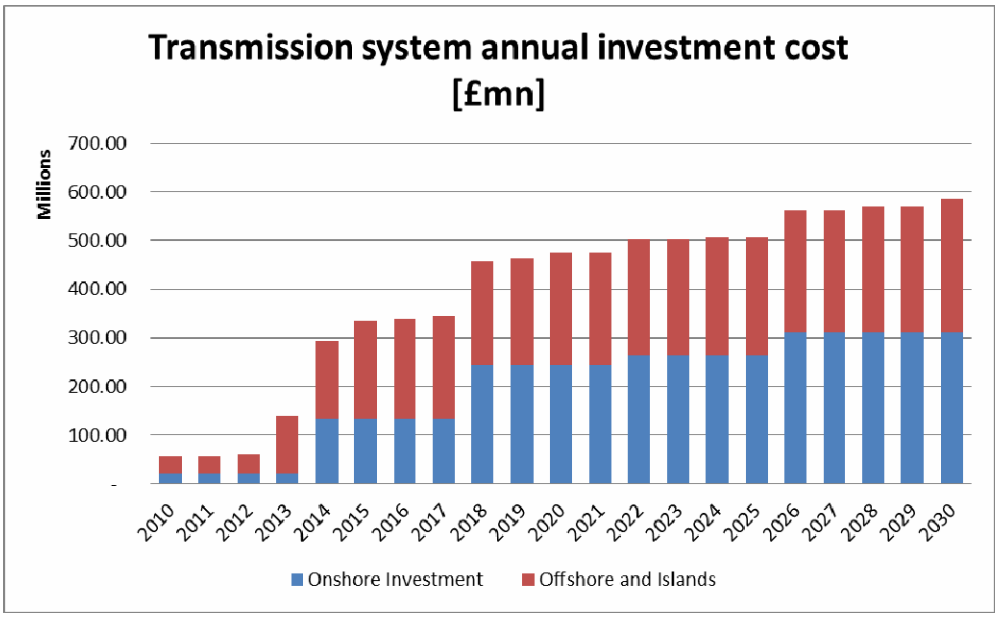
Total investment is slightly higher in iteration 7 of the models than iteration 8, driven by the extra reinforcements required between the south west and the south east.

Figure 4.16
Cumulative Annualised Transmission Investment Cost – Iteration 7 (2010 £Mn)



Source: NERA/Imperial Analysis

Figure 4.17
Cumulative Annualised Transmission Investment Cost – Iteration 8 (2010 £Mn)



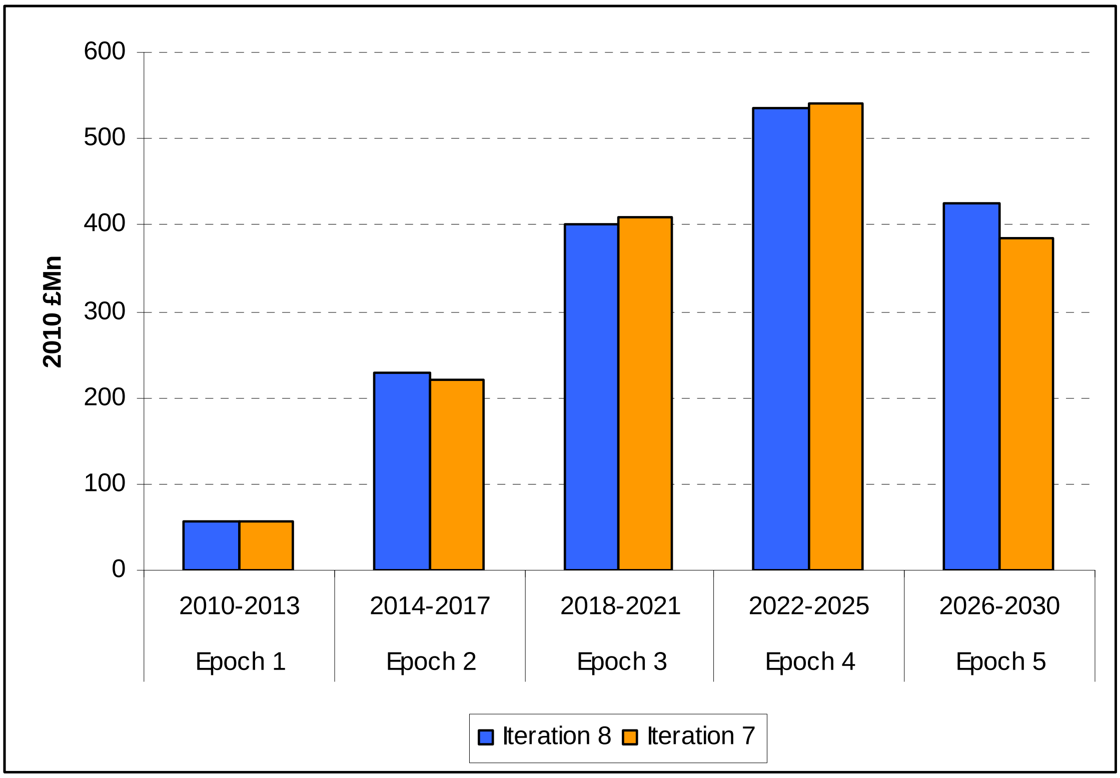
Source: NERA/Imperial Analysis

4.4.2. Constraint costs

As described in Section 2.2.2, our DTIM model makes a trade-off between onshore investment costs, which include the DC links, and the cost of constraints.

Figure 4.18 presents constraint costs for each DTIM modelling epoch. The figure shows that using both the final and penultimate runs of the model, we obtain similar constraint cost estimates, with a difference between the two scenarios of less than 3% over the modelling horizon. Through our calibration exercise, we found that the constraint costs estimated by our model are similar to those forecast in National Grid's "Gone Green Scenario" when we use common input assumptions.

Figure 4.18
Transmission Constraint Costs per Epoch (2010 £Mn)



Source: NERA/Imperial Analysis

4.4.3. Transmission losses

Transmission losses currently represet around 1.5% of net energy consumption. Our modelling results in the locational scenario indicate that losses increase between epochs 1 and 2 due to investment in new renewable generation in Scotland, which increases North to South power flows.

In iteration 8 of the locational scenario (see Table 4.1), losses then fall in the two subsequent epochs as power flows along the main power corridors decrease because conventional plant decomission in the North and Midlands, and are replaced by new plants closer to the main load centres in the south east. In the final epoch losses increase as more plant comes online in south west and east, and so power flows across the southern boundaries increase.

In iteration 7 of the locational scenario (see Table 4.2) losses are slightly higher than at iteration 8, driven by the increased power flows from the south west to the south east due to the development of more new CCGT capacity in the south west.

Table 4.1
Locational Scenario (Iteration 8) Transmission Losses

	2010/2013	2014/2017	2018/2021	2022/2025	2026/2030
	Epoch 1	*Epoch 2*	*Epoch 3*	*Epoch 4*	*Epoch 5*
Losses (TWh) per Epoch	17.6	26.1	26.6	21.6	29.2
Losses (TWh) Annual	4.4	6.5	6.7	5.4	5.8
Total Energy (TWh) per Epoch	1,293.5	1,309.2	1,370.7	1,445.1	2,026.8
Total Energy (TWh) Annual	323.4	327.3	342.7	361.3	405.4
% of Total Energy	1.4%	2.0%	1.9%	1.5%	1.4%

Source: NERA/Imperial Analysis

Table 4.2
Locational Scenario (Iteration 7) Transmission Losses

	2010/2013	2014/2017	2018/2021	2022/2025	2026/2030
	Epoch 1	*Epoch 2*	*Epoch 3*	*Epoch 4*	*Epoch 5*
Losses (TWh) per Epoch	17.1	27.3	29.9	27.7	36.1
Losses (TWh) Annual	4.3	6.8	7.5	6.9	7.2
Total Energy (TWh) per Epoch	1,293.4	1,311.4	1,375.9	1,439.8	1,898.9
Total Energy (TWh) Annual	1,293.5	1,309.2	1,370.7	1,445.1	2,026.8
% of Total Energy	1.3%	2.1%	2.2%	1.9%	1.9%

Source: NERA/Imperial Analysis

4.4.4. Comparison of iterations 7 and 8

As Table 4.3 shows, shifting the portfolio of new generation capacity between the south east and the south west changes our estimate of transmission system costs (investment costs, constraints costs plus losses) by less than 10% in NPV terms over the period to 2030, even though this would require significant reinforcement of the grid in the south of England.

Table 4.3
Transmission System Costs: Iteration 7 vs. Iteration 8

NPV to 2030 @ 3.5%, 2010 Prices	**Iteration 7**	**Iteration 8**	**Difference (%)**
Cost of Transmission Investments	4,550	4,151	9.6%
Cost of Transmission Constraints	1,063	1,083	-1.8%
Cost of Transmission Losses	6,517	5,844	11.5%
Total	**12,131**	**11,078**	**9.5%**

Source: NERA/Imperial Analysis

Hence, overall transmission system costs are similar irrespective of where in the south of GB new conventional capacity is located. We obtain this result because a main driver of transmission system costs over our modelling horizon is the proportion of generation (both conventional and renewable) that locates in Scotland. Hence, we envisage that locating a larger proportion of new OCGT and CCGT investment in the midlands, for example, rather than in the south east or south west would have only a small impact on the results presented above.

As described in Section 4.2.5, we use the average of transmission system costs at iterations 7 and 8 for our welfare analysis in Chapter 6.

4.5. Conclusions

The results presented in this chapter result from a process of iteration between our market models, to predict the quantity, technology and location of new generation investment, and our transmission system models, to predict transmission investment requirements, constraint costs and TNUoS charges.

We found that after eight iterations of our market and transmission system models, the patterns of TNUoS charges that emerge over our modelling horizon remained reasonably stable between iterations. In general, we estimated that TNUoS charges in Scottish zones will almost double in real terms from their current levels of around £17/kW/yr to around £34/kW/yr on average by 2030. This result is driven by the need for reinforcement investment on the border between England and Scotland, and in particular by the need to construct offshore HVDC links to reinforce the grid as new renewables development takes place in Scotland. At the same time, TNUoS charges in England and Wales trend downwards on average. In general, TNUoS charges in the north of England and Wales remain higher than those in zones close to the load centre in the south east.

Our market model predicts that this divergence in TNUoS charges between Scotland and England and Wales discourages new investment in conventional thermal generation capacity in the north of England and Scotland, as variation in TNUoS and NTS charges are the main drivers of locational investment incentives. Hence, our analysis shows that the current structure of cost-reflective TNUoS charges provides strong incentives for conventional generators to locate in areas of the system where demand exceeds installed generation capacity.

Regarding our projected pattern of new renewables investment, our analysis indicates that the locational charging regime incentivises investment in new wind capacity across the whole of GB, with offshore development concentrated in the south west of England, the Dogger Bank, and the west coast of Scotland. Over the whole period, most onshore developments take place in Scotland, including some development on the Scottish islands, although around 3GW of onshore wind development takes place in England and Wales.

Our modelling also indicates that the target of 30% of renewables in power generation is achieved by 2020, and CO_2 emissions in the power sector remain broadly in line the target we assume that puts the power sector on course for full decarbonisation by 2030.

Overall, locational TNUoS charges reflect the incremental (or decremental) cost of reinforcing the transmission system due to the presence of generation capacity in a given zone.[54] These signals affect the relative profitability of generation in different parts of the country and hence the locations where investors choose to develop new transmission capacity. Our modelling also suggests that government renewables and CO2 reduction targets are achievable in the locational scenario.

54 The levels of incremental reinforcement costs change over time due largely due to our assumption that the Scotland-England boundary will be reinforced using offshore HVDC cables.

5. Uniform Scenario Modelling Results

In this chapter, we describe the uniform scenario modelling results. We also describe the impact of assuming uniform TNUoS charges compared to the locational scenario on our projections for the power market, renewables investment patterns, transmission investment requirements, constraint costs, transmission losses and TNUoS charges.

5.1. Modelling procedure

As for the locational scenario, we used iterations between our power market and transmission system models to achieve reasonable convergence in TNUoS charges. In the locational scenario, the "seed" we used to begin this process of iteration was the assumption that current charges remain constant in real terms throughout our modelling horizon. For the uniform scenario, we began our iterative procedure assuming that TNUoS charges are zero throughout the modelling horizon. However, unlike the locational modelling scenario, updating the TNUoS charges assumed in the market model in the second iteration did not have any impact on the location of conventional generation investment, and only a negligible impact on renewables investment decisions. The model therefore converged after two iterations, with no instability of results arising due to changing TNUoS charges.

5.2. Locational Investment Decisions

5.2.1. Overview of modelling results

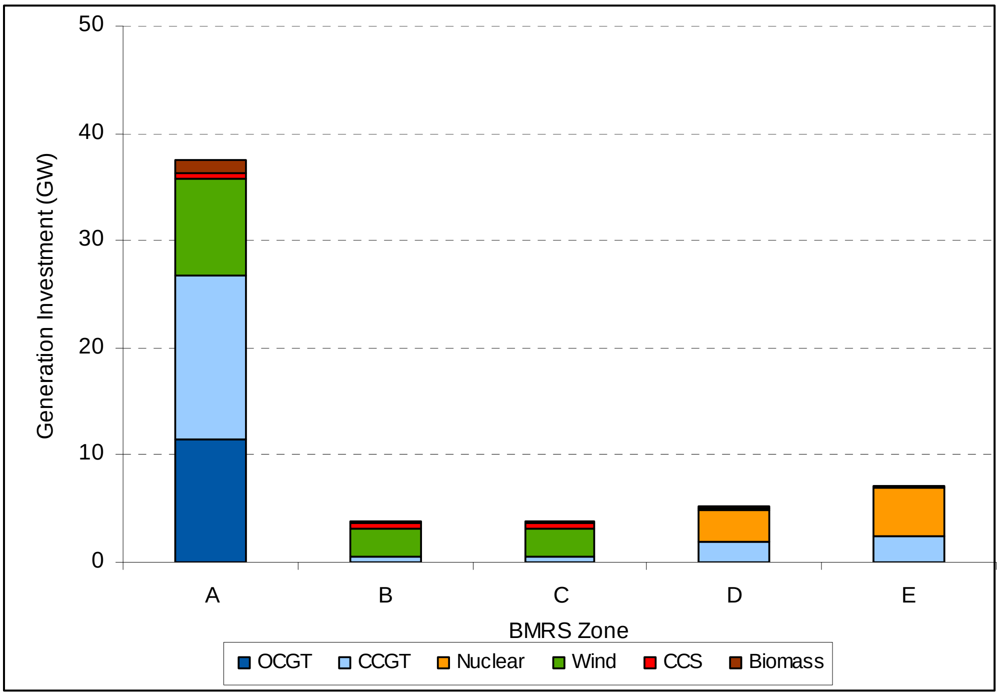
As we describe in more detail below, the uniform TNUoS charging scenario significantly changes the locational decisions of new conventional and renewable generators compared to the locational scenario.

In the locational scenario our model predicted that the majority of new thermal investment would go into southern BMRS zones close to the areas with the highest net demand. In contrast, in the uniform case most conventional generation investment takes place in Scotland (i.e. BMRS zone A), as Figure 5.1 shows. Without the locational cost differentiation provided by TNUoS charges, the next most significant difference in the locational costs of conventional gas-fired investment is due to NTS charges. Hence, in the uniform scenario our model chooses to develop new gas-fired capacity in Scotland because of the relatively low NTS charges, due to the potential to site new CCGTs close to NTS entry terminals, i.e. St Fergus.

Figure 5.1 also shows that new renewable generation capacity would be more concentrated in Scotland than in the locational scenario (see below for a detailed comparison), with less new wind capacity developed in the southern BMRS zones in England and Wales.

Regarding new nuclear capacity, as described in Section 3.3.3, in the uniform scenario we first allow the model to choose the quantity of new nuclear capacity that comes online, then we assume that this capacity comes online at those sites where developers have announced the closest proposed online dates for new nuclear projects. Hence, new nuclear capacity comes online in BMRS zones D and E.

Figure 5.1
Location of New Generation Investment to 2030 (GW): Uniform Scenario



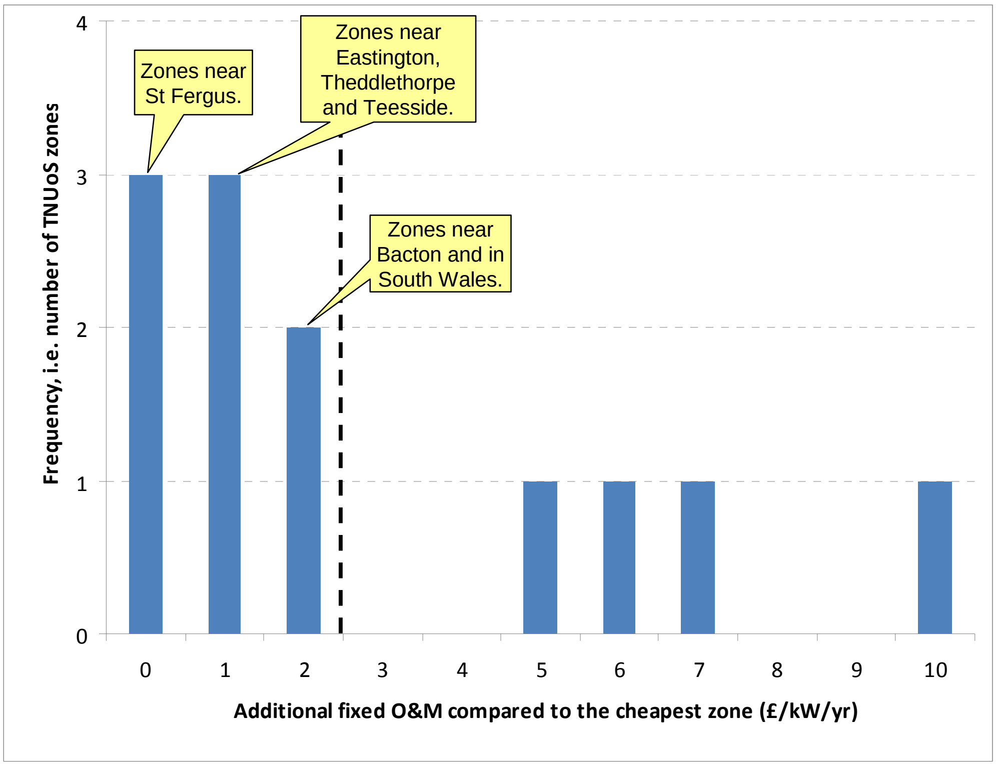
Source: NERA/Imperial Analysis

5.2.2. Alternative distribution of new conventional generation

This analysis demonstrates that it would be optimal for generators to develop most new generation capacity in Scotland with uniform TNUoS. However, in the cse of conventional gas-fired generation capacity, the differences in NTS exit charges that drive the model to locate virtually all new capacity in Scotland are relatively small. Figure 5.2 shows our estimated fixed O&M of new build greenfield CCGTs in our uniform case, presented as the difference from a baseline of fixed O&M of plants in the cheapest zones for developing new capacity. The chart shows that with uniform TNUoS the three cheapest zones for developing new CCGTs are in Scotland, close to St Fergus, and that there are five other zones where new entry is only £1-2/kW/year more expensive, with all other zones being at least £5/kW more expensive.

To provide a more realistic uniform scenario for assessment, we therefore take the new investment in OCGT and CCGT capacity predicted by our market model, and spread it out evenly across the eight generation TNUoS charging zones where we estimate that new entrants would have annual fixed O&M costs within £2/kW/year of the lowest fixed O&M. We assume that no new development takes place in zones where fixed O&M is £5/kW/year or more higher than in the cheapest zone.

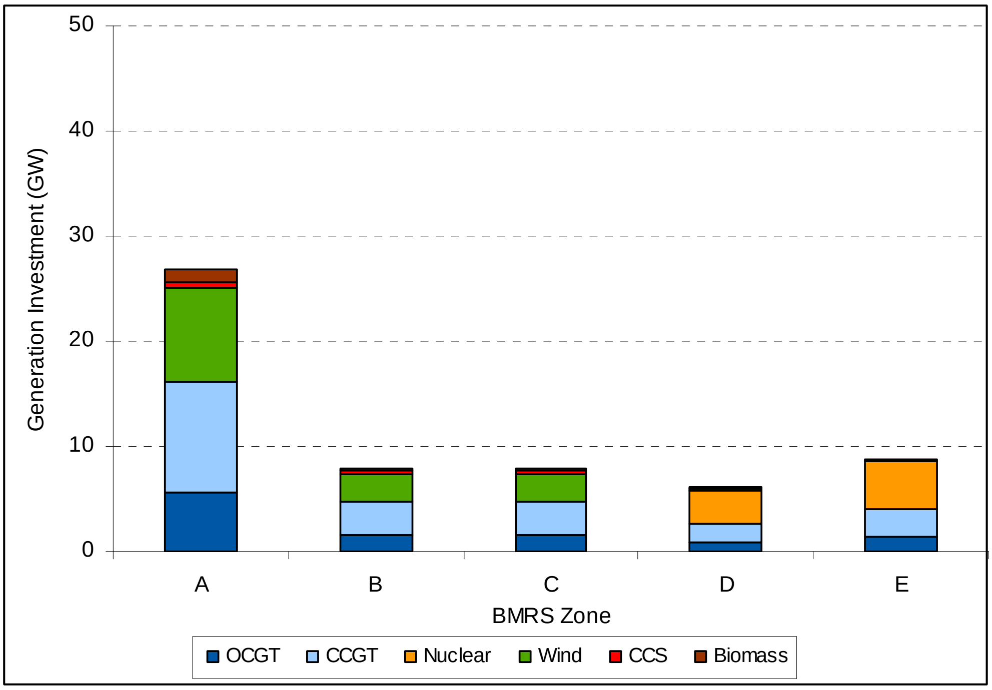
Figure 5.2
Distribution of Additional New CCGT Fixed O&M



Source: NERA/Imperial Analysis

The locational capacity mix resulting from this procedure is presented in Figure 5.3. In this case, new OCGT and CCGT capacity is built in all BMRS zones, although the majority is still developed in zone A, which includes Scotland. All the detailed modelling results presented in the remainder of this chapter assume the distribution of new OCGT and CCGT generation capacity shown in Figure 5.3.

Figure 5.3
Assumed Distribution of New Investment by BMRS Zone



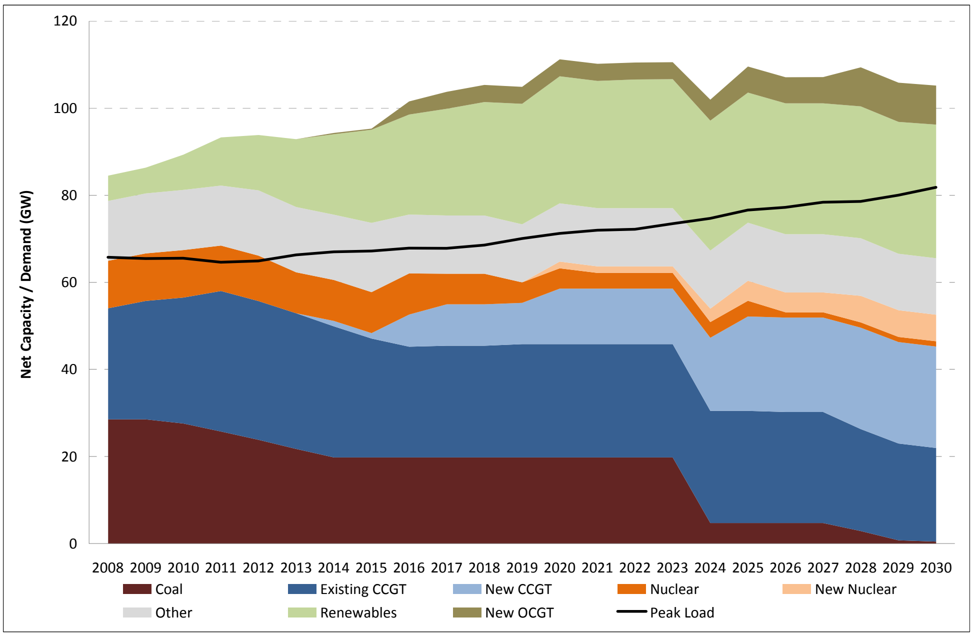
Source: NERA/Imperial Analysis

5.3. Market Modelling Results

5.3.1. Supply-demand balance in the wholesale power market

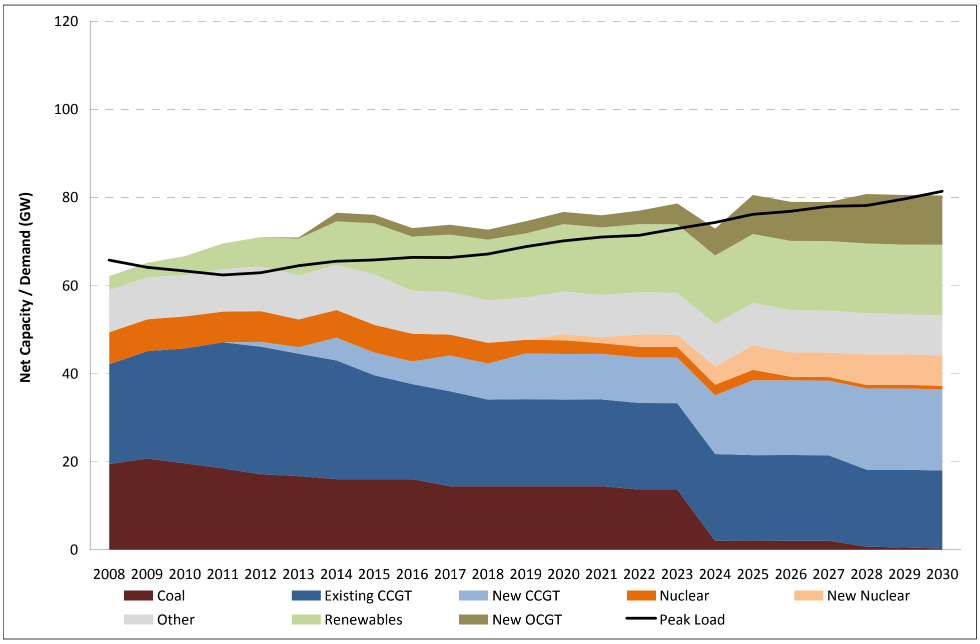
Figure 5.4 shows that the overall supply-demand balance in the wholesale power market is similar in the uniform scenario to our projections in the locational scenario. The model predicts similar timing and quantities of investment in CCGT, OCGT and new nuclear capacity as in the locational scenario. As a result, the generation mix in the uniform scenario (Figure 5.6) is also similar to that in the locational scenario (Figure 4.6). Hence, the forecasts of derated generation capacity (Figure 5.5) and generation output (Figure 5.6) are also similar to the projections from the locational scenario.

Figure 5.4
GB Peak Load and Installed Capacity by Technology (GW)



Source: NERA/Imperial Analysis[55]

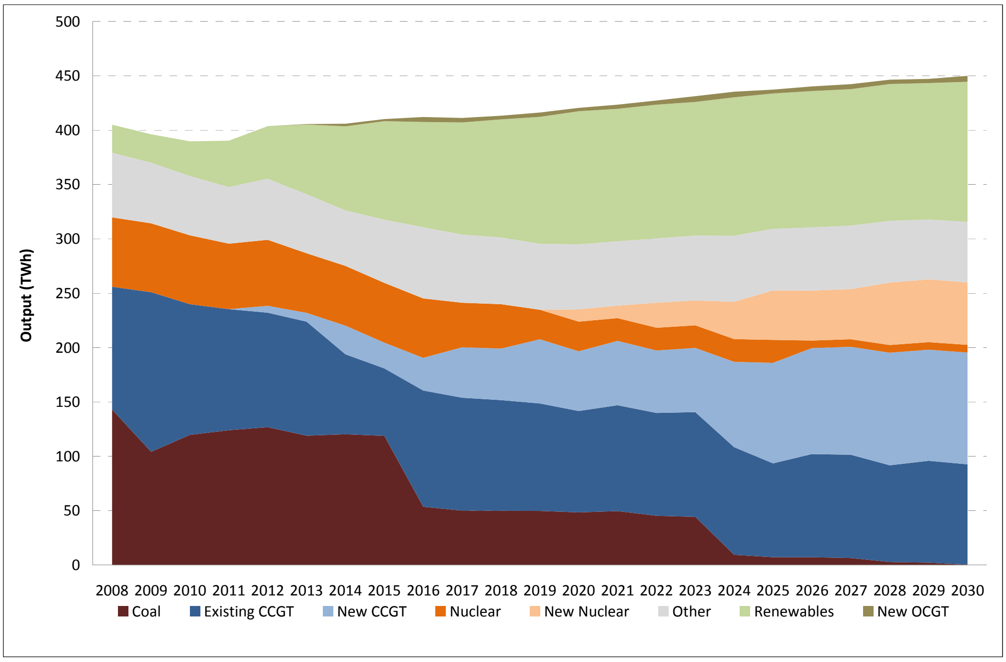
Figure 5.5
GB Peak Load and Derated Capacity by Technology (GW)



Source: NERA/Imperial Analysis

55 We present in Appendix G the forecast capacity and demand data behind this chart.

Figure 5.6
Generation Output by Technology (TWh)

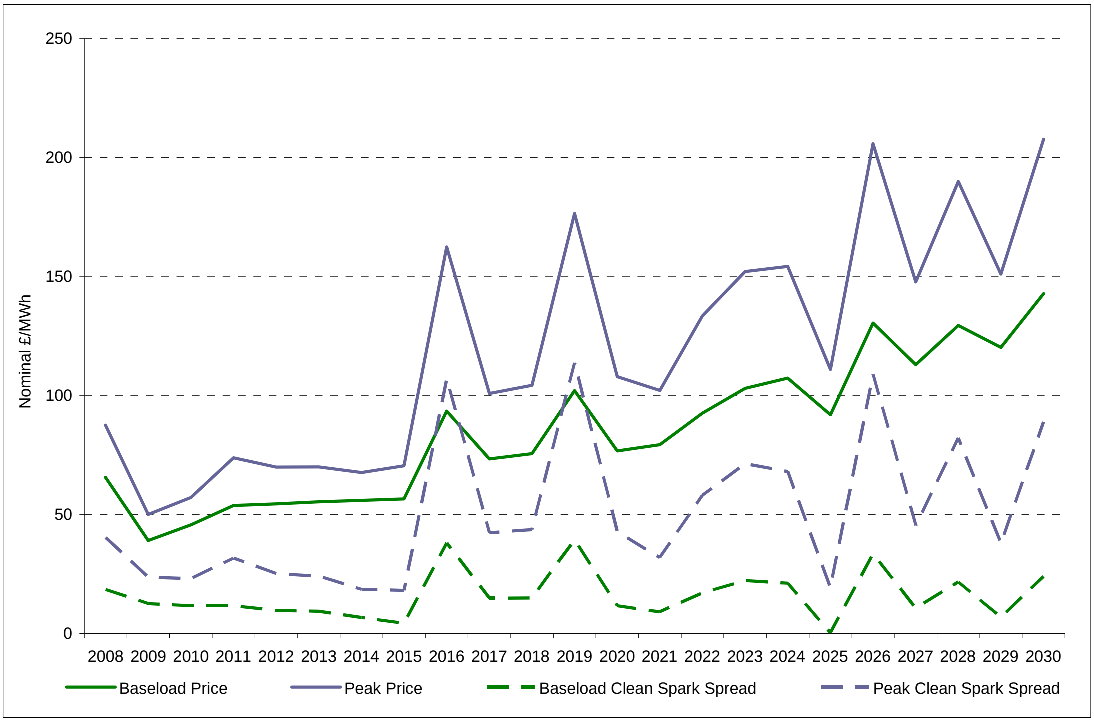


Source: NERA/Imperial Analysis

5.3.2. Wholesale power prices

Figure 5.7 shows our projections of wholesale power prices and clean spark spreads in the uniform scenario. Because the supply-demand mix is similar to the locational scenario, and underlying commodity prices are identical, the price forecast in the uniform scenario follows a similar trajectory to the price forecast in the locational scenario (see Figure 4.10).

Figure 5.7
Wholesale Power Prices and Clean Spark Spreads (Nominal £/MWh)



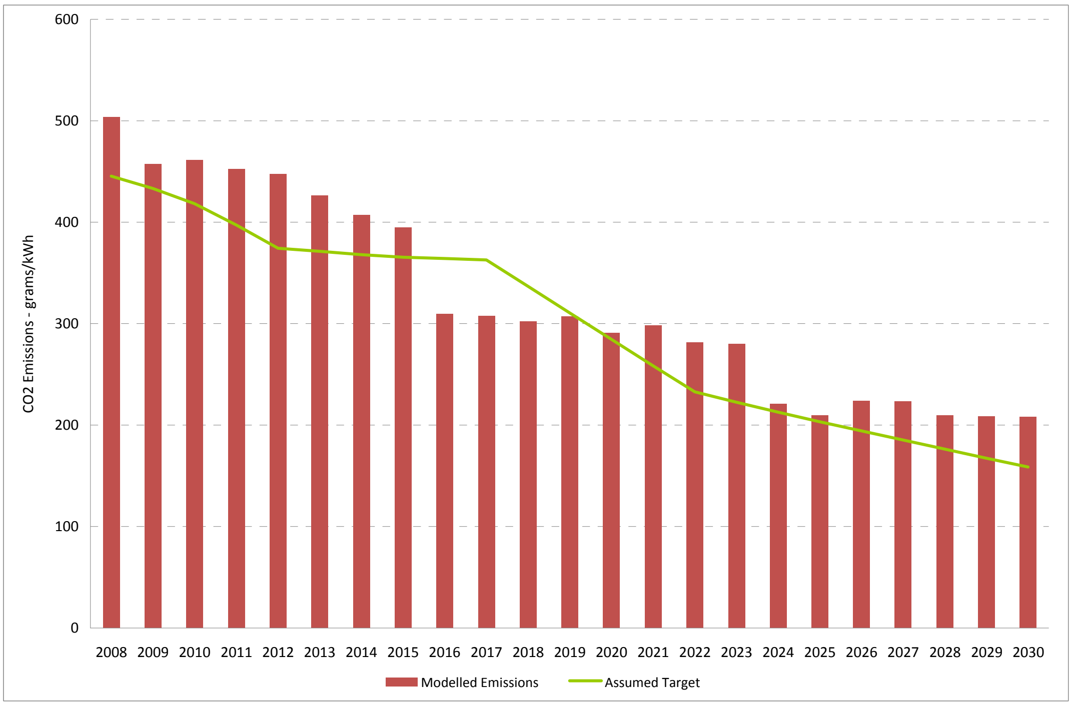
Source: NERA/Imperial Analysis

5.3.3. Emissions projections

Because the production mix is similar in this scenario, the projection of emissions to 2030 is also similar, remaining broadly in line with government targets. Hence, in both the uniform and locational scenarios emissions are close to the target trajectory required to decarbonise the UK power sector by 2050, and close to the "baseline" in the EMR consultation document.

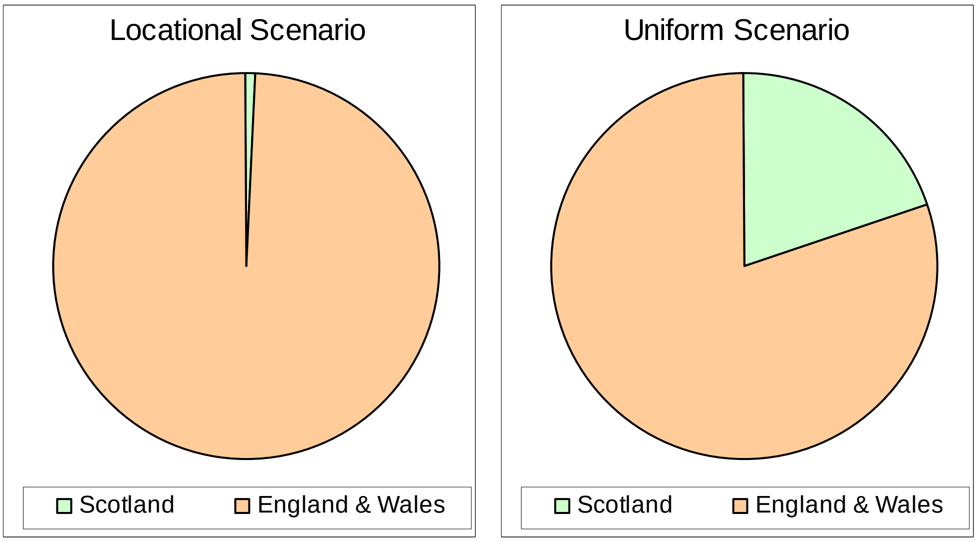
However, by 2030 the share of CO2 emissions from Scotland increases significantly compared to the locational scenario due to the large share of new CCGT capacity that the model predicts will be sited in Scotland.

Figure 5.8
CO2 Emissions vs. Assumed Target (grams per kWh)



Source: NERA/Imperial Analysis

Figure 5.9
Share of GB CO2 Emissions by Region in 2030



Source: NERA/Imperial Analysis

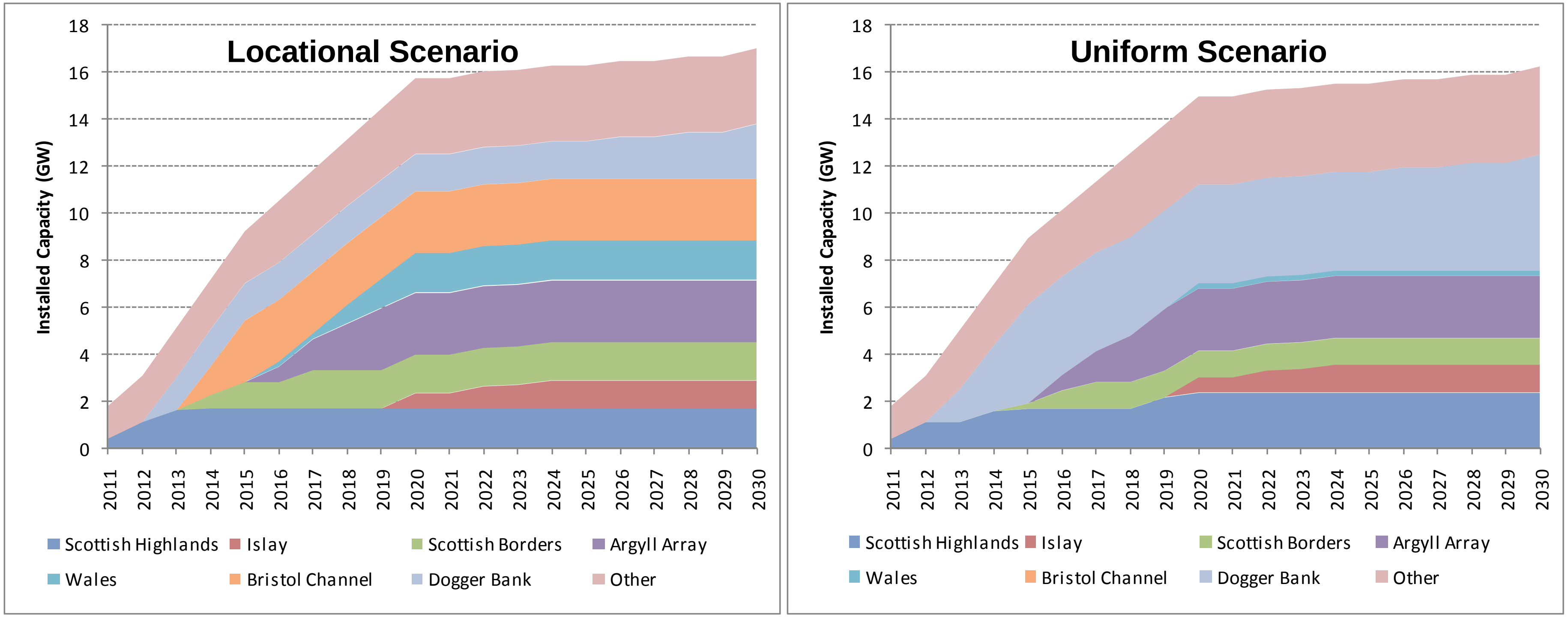
5.3.4. Renewables investment patterns

Replacing locational TNUoS charges by a uniform charge also affects our projected patterns of new renewables investment. As Figure 5.10 and Figure 5.11 show, uniform TNUoS charges incentivise the model to develop less capacity in England and Wales, choosing instead to develop more capacity onshore in Scotland, both on the mainland and on the Shetlands and Western Isles. Within mainland Scotland, uniform TNUoS charges also incentivise more development in the Highlands and less in the Lowlands.

The other main change between the locational and uniform scenarios is that the R3 offshore developments in England shifted from the Bristol Channel to the Dogger Bank (see Figure 5.10 and Figure 5.12), which requires additional investment in infrastructure to connect offshore wind farms that are sited further out to sea. This change compared to the locational scenario occurs principally because we assume that the local asset charges faced by offshore wind developers are socialised in the uniform scenario. Hence, investment on the Dogger Bank becomes more attractive than in the Bristol Channel as the model can select projects with a higher load factor without incurring significant infrastructure costs. A similar quantity of offshore wind development takes place in Scotland in both cases.

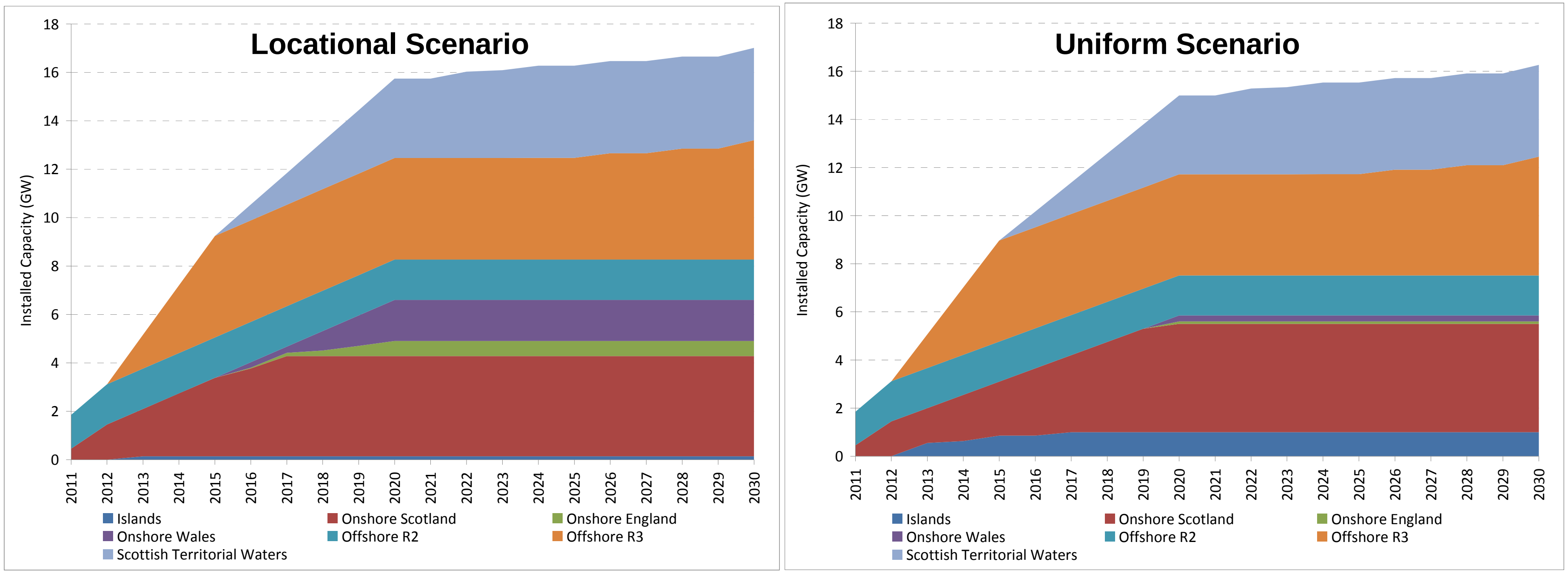
Figure 5.10 and Figure 5.11 also show that the total quantity of installed capacity selected by our model was slightly lower in the uniform scenario. This occurs because the model selects a higher proportion of offshore projects and projects in remote locations with higher load factors. However, the total quantity of energy produced from renewable sources is the same in both scenarios.

Figure 5.10
Regional Wind Investment Patterns (Locational vs. Uniform)



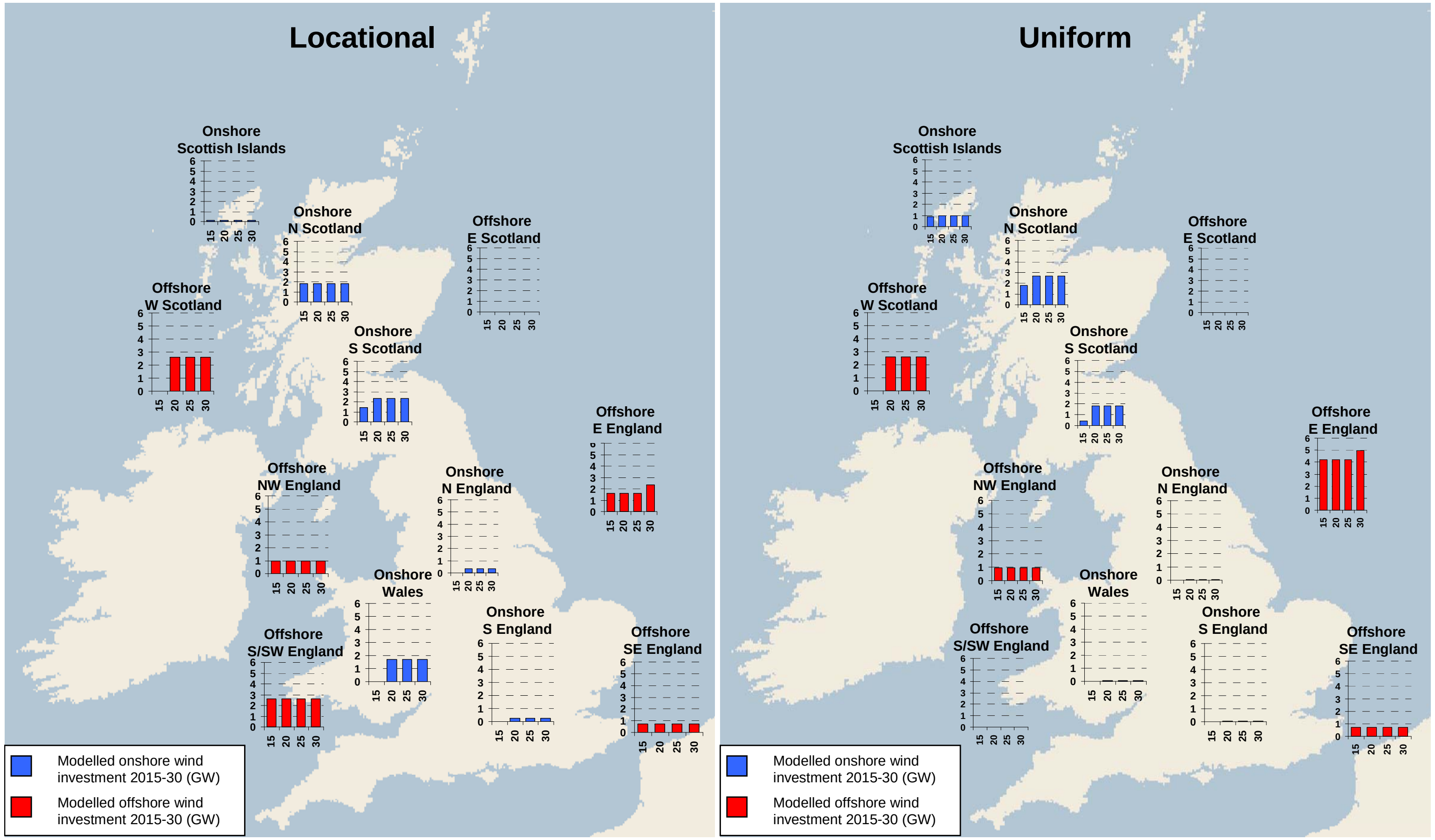
Source: NERA/Imperial Analysis

Figure 5.11
Aggregated Regional Wind Investment Patterns (Locational vs. Uniform)



Source: NERA/Imperial Analysis

Figure 5.12:
Maps of Regional Wind Investment Patterns (Locational vs. Uniform)



Source: NERA/Imperial Analysis

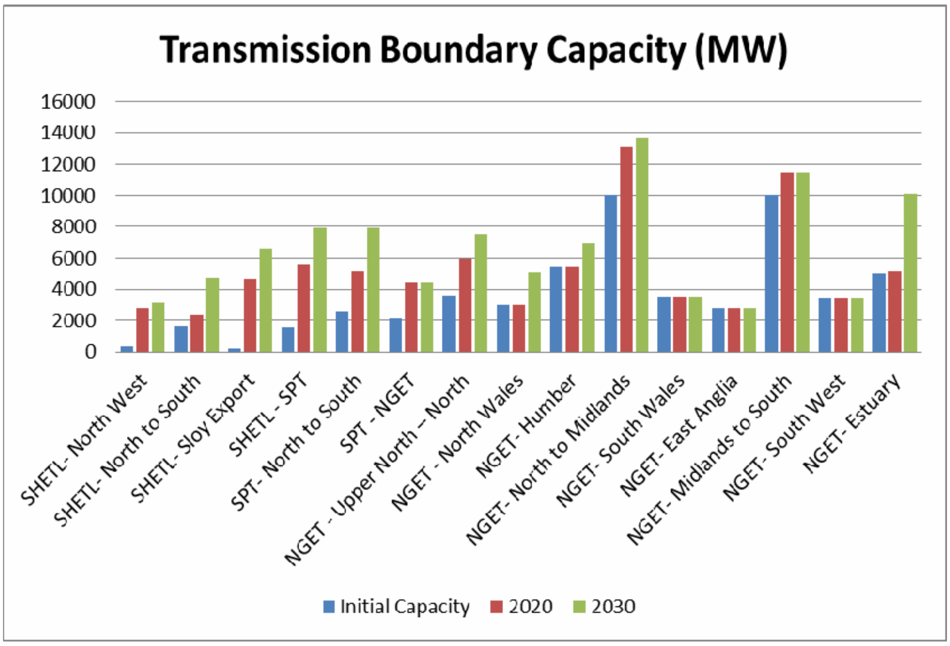
5.4. Transmission System Modelling Results

5.4.1. Transmission investment requirements

The uniform charging scenario requires more onshore transmission investment in Scotland than in the locational scenario, as well as larger DC-link reinforcements than in the locational scenario, as Figure 5.13 and Table 5.1 show. The onshore investment requirements in England are similar in the locational and uniform scenarios although the model does build extra capacity on the North to Midlands boundary to accommodate increasing north to south power flows. Also the North Wales boundary investment is now mainly driven by the Western DC link injections in the area rather than the extra new nuclear plant capacity, which locates in the south of England in this scenario.

The main change in transmission investments compared to the locational scenario is the increased development of offshore DC lines, driven by both the increased wind capacity and the new OCGT and CCGT plants in Scotland that the model constructs after 2020. In this scenario, the model builds only one extra western DC link in 2022 than in the locational scenario. As described above, we assume that AC capacity on the Cheviot boundary is limited to 4.4GW.

Figure 5.13
Transmission Investment per DTIM boundary Uniform Scenario



Source: NERA/Imperial Analysis

Table 5.1
Uniform Scenario DC Link Investment by Epoch

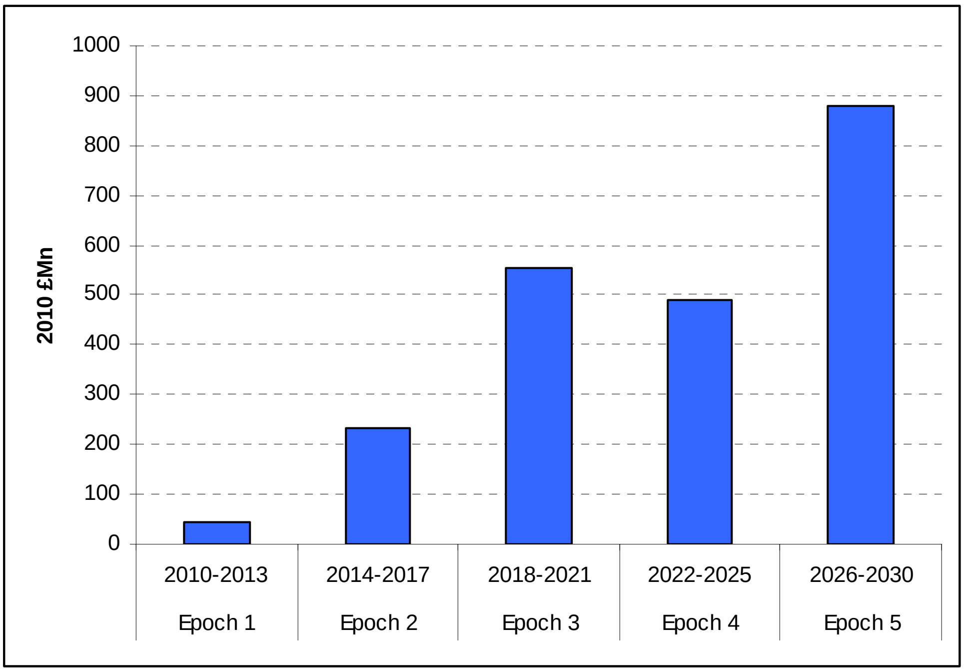
DC Link	2010/2013 [MW]	2014/2017 [MW]	2018/2021 [MW]	2022/2025 [MW]	2025/2030 [MW]	Total
Eastern	-	-	1,971	-	-	1,971
Western	-	1,800	-	1,800	-	3,600

Source: NERA/Imperial Analysis

5.4.2. Transmission constraint costs

Figure 5.14 shows our forecast of transmission constraint costs associated with the uniform scenario generation and transmission capacity forecasts.

Figure 5.14
Uniform Scenario Constraint Costs (2010 £ per epoch)



Source: NERA/Imperial Analysis

5.4.3. Transmission losses

As Table 5.2 shows, transmission losses in the uniform case increase over the course of the modelling horizon, mainly due to increased North to South power flows along the main transmission corridor between northern England to the Midlands and the South of the country, due to the larger share of renewable and conventional generation located in the North.

Table 5.2
Uniform Scenario Transmission Losses

	2010/2013 *Epoch 1*	2014/2017 *Epoch 2*	2018/2021 *Epoch 3*	2022/2025 *Epoch 4*	2026/2030 *Epoch 5*
Losses (TWh) per Epoch	21.3	38.5	42.2	42.9	55.1
Losses (TWh) Annual	5.3	9.6	10.5	10.7	11.0
Total Energy (TWh) per Epoch	1,289.5	1,320.7	1,400.5	1,480.4	1,993.0
Total Energy (TWh) Annual	322.4	330.2	350.1	370.1	398.6
% of Total Energy	1.7%	2.9%	3.0%	2.9%	2.8%

Source: NERA/Imperial Analysis

5.5. Quantifying the Impact of Uniform TNUoS

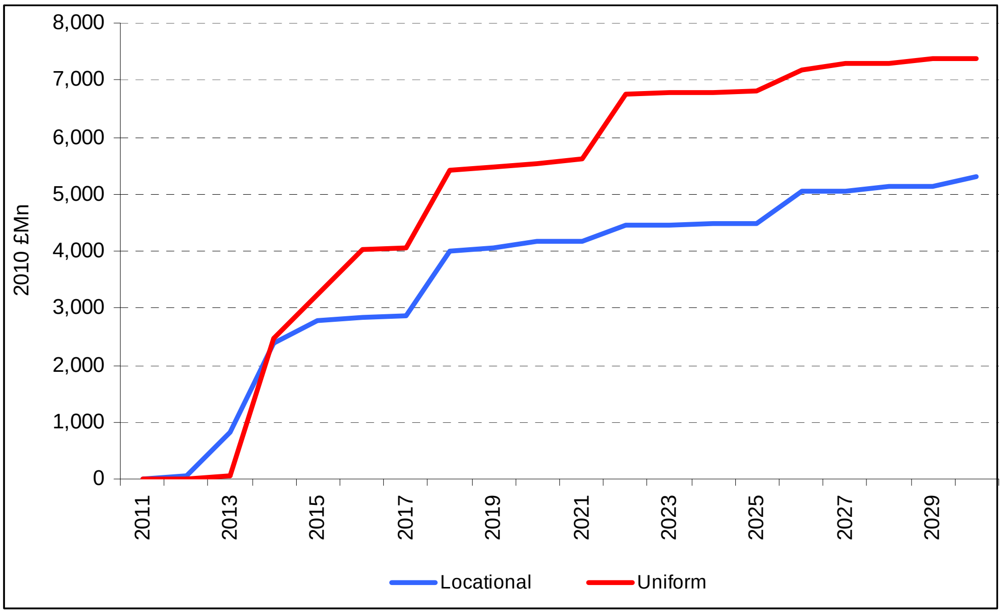
5.5.1. The impact on transmission investment and constraint costs

As Figure 5.15 and Figure 5.16 show, transmission investment and constraint costs are substantially higher than in the locational scenario. This is driven by a higher proportion of new conventional and renewable generation capacity locating in Scotland, triggering additional reinforcement on the Cheviot boundary. It is also due to offshore wind farms locating further from shore (e.g. on the Dogger Bank), which increases offshore infrastructure costs. However, because of the approach we have taken to defining modelling assumptions, there are a number of reasons why we may have understated these impacts of uniform TNUoS.

For example, as we note in Section 2.2.2, our model assumes that new transmission investments are delivered at the point in time when it is efficient (i.e. least-cost) for them to come online. If we modelled a scenario where transmission investments come online later than is optimal, due to delays in obtaining planning permission for new infrastructure for example, we would force the model to depart from the mix of constraint costs and transmission investment costs that minimes total costs. Given the higher investement requirements in the uniform scenario, we would expect the increase in total transmission costs resulting from planning delays to be higher in the uniform than in the locational scenario.

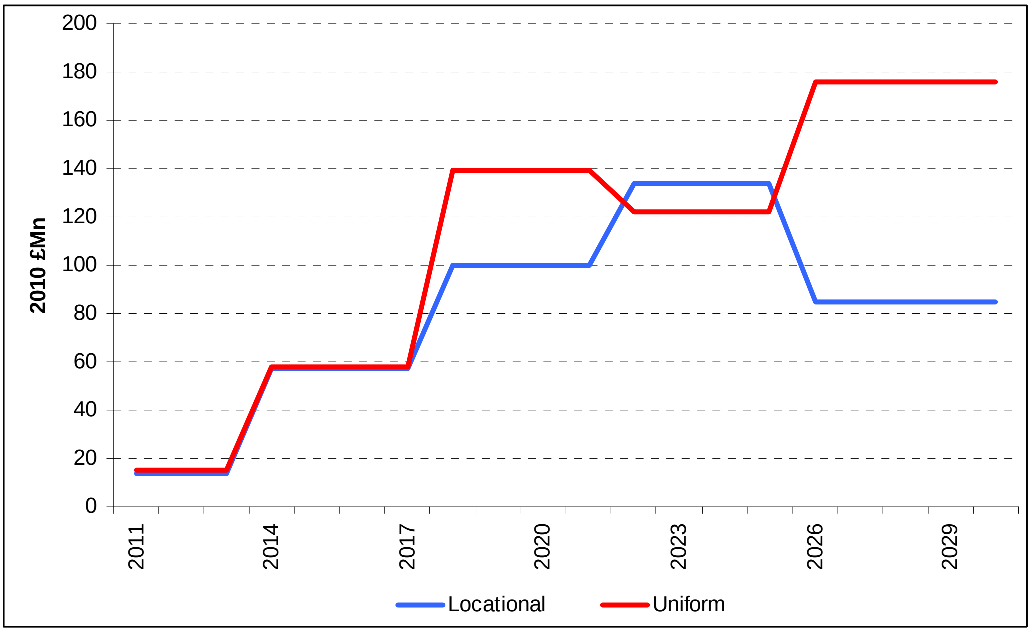
In our modelling, we have also assumed that generators' bids and offers into the balancing mechanism reflect their short-run marginal costs of production. If we assumed some spread between the costs of constraining off and constraining on generators, due for example to the ability of generators to capture the market value of output in the balancing market or even just the impact of unit commitment costs, it would increase the costs of resolving transmission constraints. Hence, the model would select more reinforcement investments as constraints are more costly to resolve. This additional investment would also tend to increase the total costs of the uniform scenario compared to the locational scenario, as constraints costs are higher on average in the uniform scenario than in the locational scenario.

Figure 5.15
Cumulative Transmission Investment Costs (2010 £Mn): Locational vs. Uniform



Source: NERA/Imperial Analysis

Figure 5.16
Annual Constraint Costs (2010 £Mn): Locational vs. Uniform Scenario

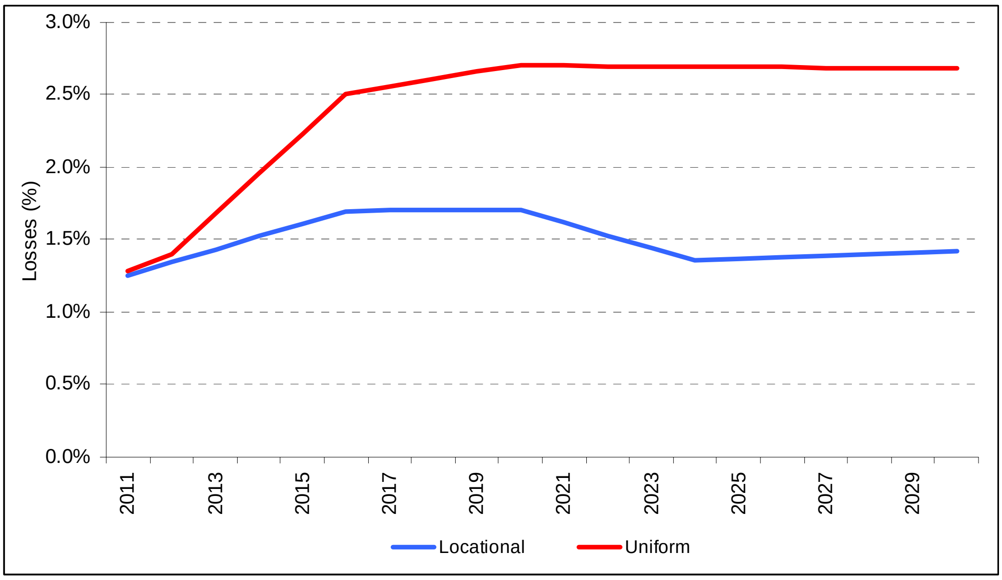


Source: NERA/Imperial Analysis

5.5.2. The impact on transmission losses

Figure 5.17 shows that losses are also substantially higher in the uniform scenario. Losses on DC links are higher in the uniform scenario due to the larger installed DC transmission capacity operating with increased utilisation, which is driven by the need to accommodate increased outputs of both conventioanl and wind generation in Scoland. In both scenarios offshore transmission losses increase as more offshore generation is connected, but in the uniform scenario offshore losses are around 25% higher. This is because the offshore generation in the uniform case is located further away form the shore, giving rise to higher losses.

Figure 5.17
Transmission Losses (% of Annual Energy Demand): Locational vs. Uniform

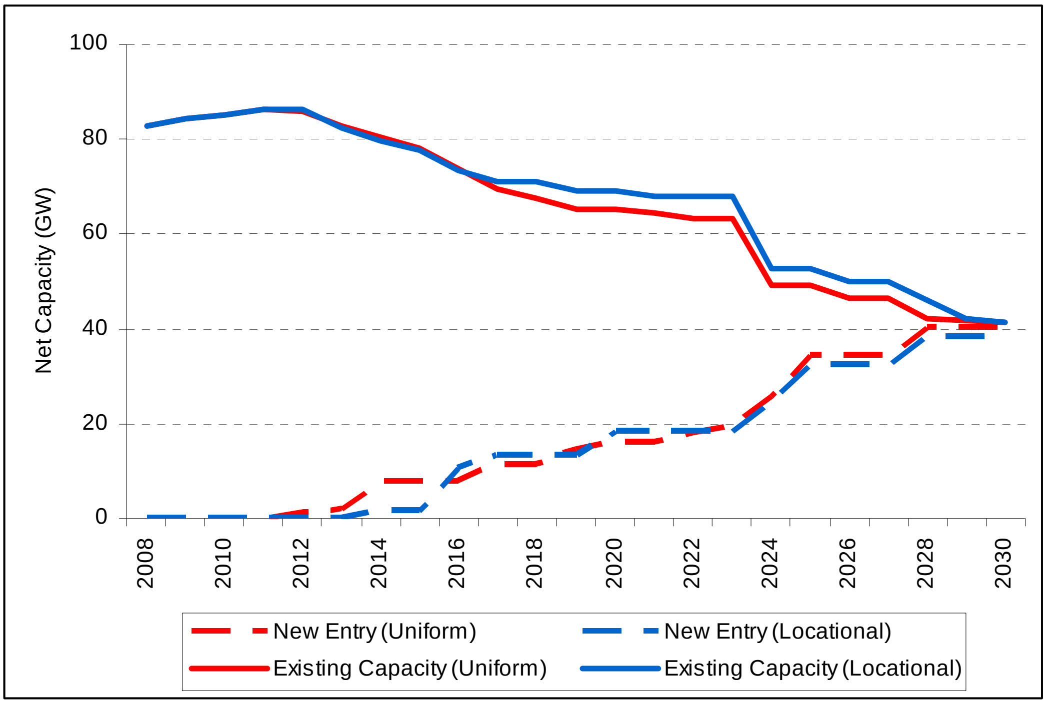


Source: NERA/Imperial Analysis

5.5.3. The impact on generation costs

Although the overall supply-demand mix in the uniform scenario (e.g. see Figure 5.4) is similar to the same projections in the locational scenario, there are some small differences in the profiles of installed capacity compared to the locational scenario. Figure 5.18 shows a comparison of how the quantity of existing generation (i.e. capacity on the system today or under construction) and new generation capacity on the system in each year of the modelling horizon differs in the locational and uniform scenarios. It shows that in the uniform case, existing capacity retires more quickly while the quantity of new investment is similar across the two scenarios in most years.

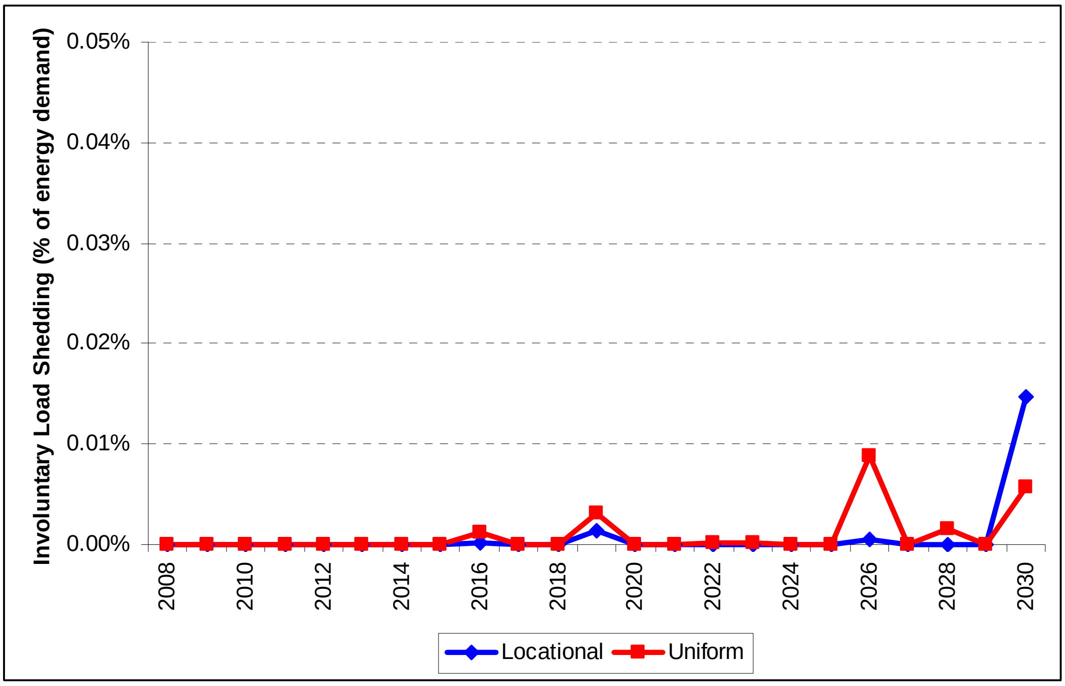
Figure 5.18
Changes in Installed Capacity: Locational vs. Uniform



Source: NERA/Imperial Analysis. Note, this chart excludes renewables.

As a result, the capacity mix in the uniform scenario provides a reserve margin of available capacity available above peak demand that is lower in the uniform scenario than the locational scenario. This occurs because the cost of new entry is higher and the model effectively economises on the provision of generation capacity. Instead, therefore, the model needs to shed more load in the uniform scenario than in the locational case, as Figure 5.19 shows, although the overall quantity of load shedding as a percentage total energy demand is small (<0.02% of annual energy demand).

Figure 5.19
Annual Load Shedding (GWh): Locational vs. Uniform Scenarios



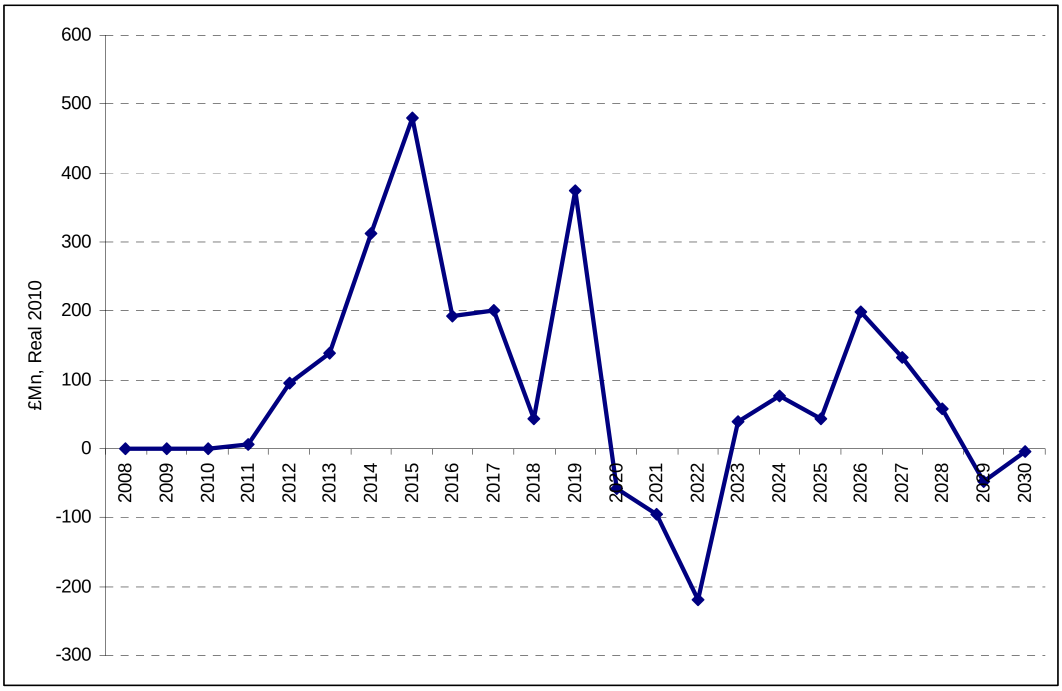
Source: NERA/Imperial Analysis

The increased cost of involuntary load shedding, which we value at €10,000/MWh, and the extra costs imposed by the earlier retirement of existing generation in this scenario shown in Figure 5.18, increases costs as shown in Figure 5.20.[56]

Figure 5.20 shows the change in those power sector costs that we assume could be avoided through decisions taken by our model. For instance, we do not include the sunk investment costs of existing generators, but we do include their fixed O&M costs as they would be avoidable through the closure of the plant. Specifically, this cost metric used to derive the data in Figure 5.20 accounts for the change fuel, CO2, fixed and variable O&M and capital costs of new non-renewable generators, as well as the cost of load shedding.

56 The earlier retirement of existing generators forces the model to incur the extra costs of dispatching plants with higher variable costs, or the costs of increased load shedding. Our assumed value of lost load is based on the VOLL parameter in the Irish Single Electricity Market.

Figure 5.20
Change in Generation Costs: Uniform Scenario Costs, minus Locational Scenario Costs (2010 £Mn, Excl. TNUoS)



Source: NERA/Imperial Analysis

5.5.4. The impact on wholesale power prices

As we describe above, in both scenarios our model predicts investment in new nuclear generation capacity that runs baseload, new CCGT capacity that runs mid-merit and new OCGTs that provide peaking capacity. To remunerate investment in this new capacity, wholesale power prices need to rise to the level that allows new investors in generation to recover the fixed costs of constructing and operating new generation capacity, as well as their variable costs of production.

For example, in our modelling, new CCGTs run at load factors of around 60%. Therefore, for new CCGTs to enter that market, average power prices across these 60% of hours need to rise to a level that at least covers their fixed and variable costs of production.

Using data from Mott MacDonald (2010),[57] we estimate that the annualised costs of constructing and operating a new gas-fired CCGT is around £83/kW/year, excluding TNUoS and NTS exit charges. At a 60% load factor, these fixed costs equate to a cost of £16/MWh.[58] However, as described in Section 2.1, our market model also accounts for the additional cost of TNUoS charges faced by new and existing generators:

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57 See Appendix A.

58 All figures in real 2010 prices.

- In the uniform scenario, the TNUoS and NTS charges incurred by a new CCGT developed anywhere in the country come to around £6.5/kW/year on average between 2020 and 2030. Hence, the total fixed costs of a new CCGT come to £89.5/kW/year, or £17/MWh.
- In the locational scenario, new CCGTs are developed exclusively in zones where TNUoS charges are negative, so the TNUoS and NTS costs incurred by a new CCGT are around *minus* £6.6/kW/year on average between 2020 and 2030. Hence, in practice the total fixed costs of a new CCGT come to £76.4/kW/year, or £14.5/MWh.

This difference means that the costs of developing new CCGT capacity increases by approximately £13/kW/year in the uniform scenario compared to the locational scenario, which equates to higher energy prices by £2.5/MWh, as the calculations in Table 5.3 demonstrate.

Table 5.3
Impact on the Cost of New CCGT Capacity During 2020-2030 (2010 £/kW/yr)

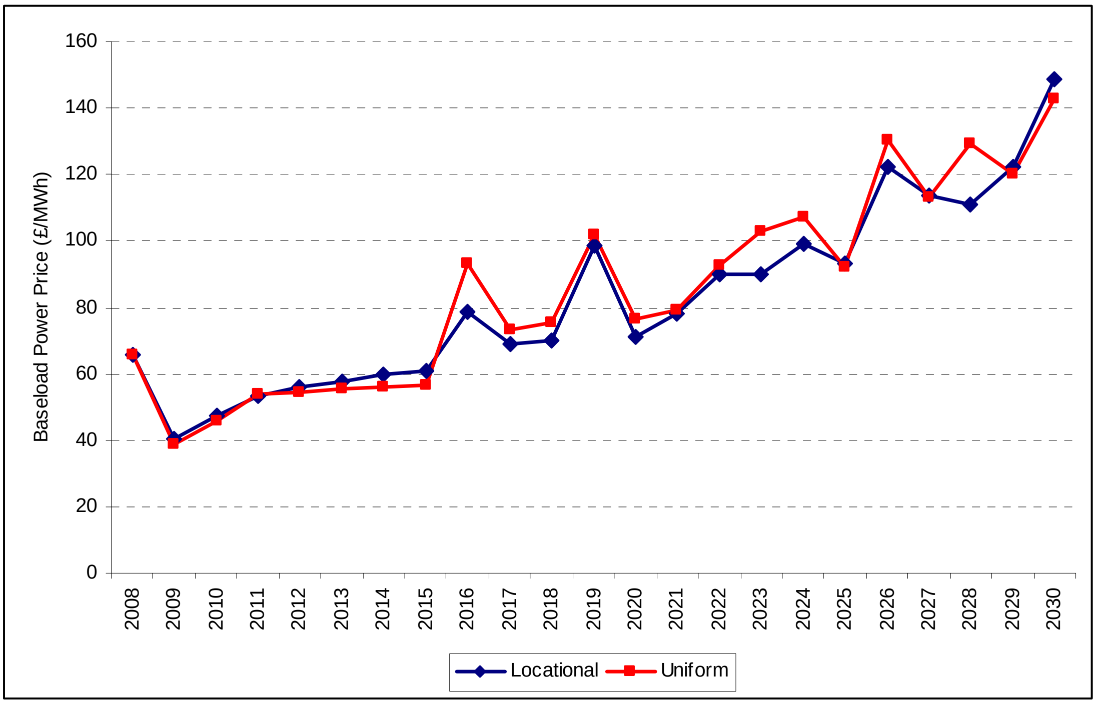
	Locational		Uniform		Difference	
	£/kW/yr	*£/MWh*	*£/kW/yr*	*£/MWh*	*£/kW/yr*	*£/MWh*
Fixed Operating and Construction Costs (Excl. TNUoS)	83.0	15.8	83.0	15.8	0.0	0.0
TNUoS Plus NTS Charges in Cheapest Zone	-6.6	-1.3	6.5	1.2	13.1	2.5
Total Fixed Costs	76.4	14.5	89.5	17.0	13.1	2.5

Source: NERA/Imperial Analysis

The intuition behind this result is that in the uniform scenario new generators pay transmission system costs calculated based on the average transmission system costs. In contrast, in the locational scenario generators pay a TNUoS charge that approximates the incremental cost of the investments they impose on the system. As the incremental cost to the transmission system of connecting in certain charging zones is negative, the costs borne by connecting generators is also negative. In the locational scenario, the charges new generators pay are reduced by a share of this cost saving, which reduces the overall cost of developing new generation capacity.

Due to the higher cost of new entry in the uniform scenario, the power prices presented in Figure 5.21 are higher in the uniform scenario than the locational scenario. Because investment in new thermal capacity is "lumpy", the year-to-year patterns of volatility differ between the two scenarios, but on average the difference in baseload prices between the two scenarios is £3/MWh (2010 prices) between 2020 and 2030.

Figure 5.21
Baseload Power Prices (Nominal £/MWh): Locational vs. Uniform Scenarios



Source: NERA/Imperial Analysis

5.5.5. The cost of meeting renewables targets

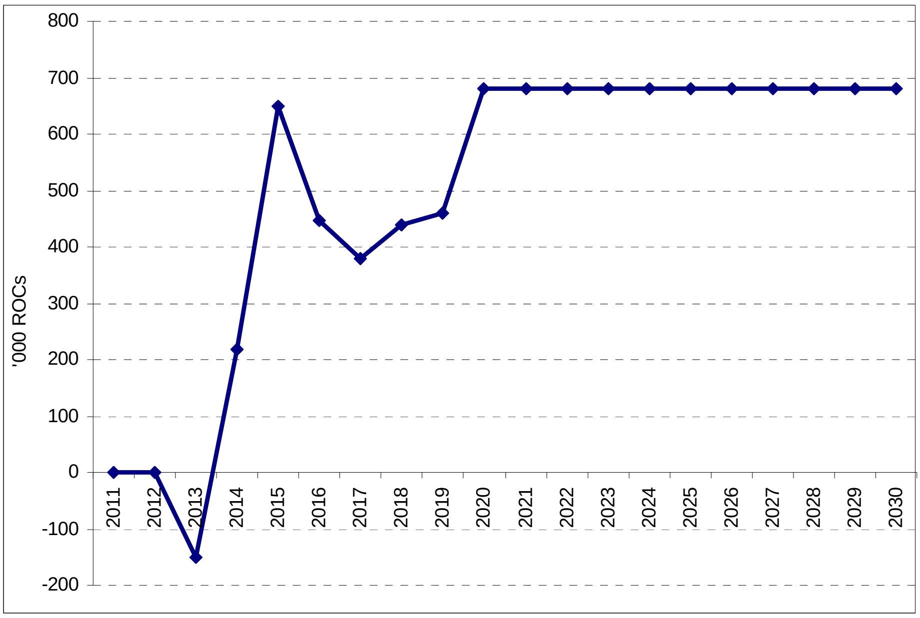
The model's choices regarding the location of new wind developments also increases costs in the uniform scenario compared to the locational scenario.

Because our model selects a higher proportion of offshore wind projects in the uniform case, the total number of ROCs issued is also higher, as Figure 5.22 shows. Because more ROCs are issued, under the guaranteed headroom provision in the RO, the overall level of the obligation on electricity retailers to present ROCs (or pay a buy-out fee) increases. This increases the renewables subsidy costs borne by the consumer.

The higher proportion of wind farms developed offshore in the uniform case also increases the total fixed costs of developing new wind farms, as Figure 5.23 shows.[59] Although the total quantity of wind capacity developed (in MW) is lower by around 5% in the uniform case, the cost per MW of developing offshore wind is more than double the cost of developing onshore wind. Hence, the overall cost of developing renewables rises in the uniform case. Moreover, because wind generators tend to locate further offshore and in more remote locations in the uniform scenario, infrastructure costs, which are not included in Figure 5.22, also increase, as we discuss above in Section 5.5.1.

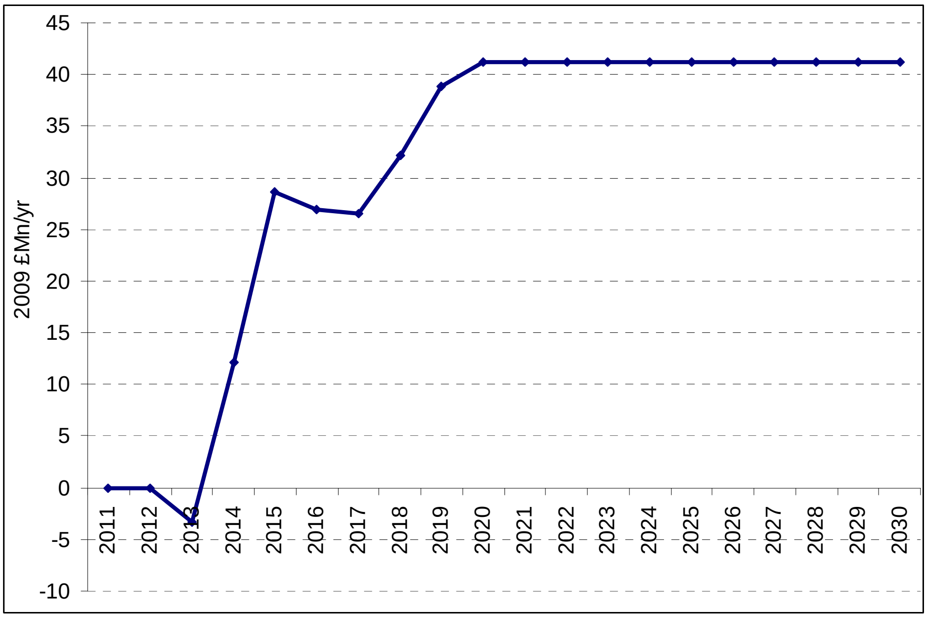
59 The figure shows the additional annualised fixed costs of developing and operating the new wind capacity selected by our model in the uniform scenario compared to the locational scenario.

Figure 5.22
ROCs Issued in Uniform Scenario, minus ROCs Issued in Locational Scenario



Source: NERA/Imperial Analysis

Figure 5.23
Change in Generation Costs: Uniform Scenario Costs, minus Locational Scenario Costs (2009 £Mn, Excl. TNUoS)



Source: NERA/Imperial Analysis

5.6. Conclusions

Our analysis has shown that the introduction of uniform TNUoS would significantly change the locational incentives faced by generators in the British power market. In contrast to the locational scenario, where generators tend to locate in the south of the country in areas of net demand, uniform TNUoS charges encourage new gas-fired generators to locate close to where other location-specific costs, predominantly NTS charges, are lowest.

We also found that the ability to avoid local asset charges incentivises development of wind farms further offshore and in more remote locations onshore where developers can obtain higher load factors. Uniform TNUoS charges also reduce the scale of wind development in England and in Wales, which is largely displaced by investment in onshore wind generation in Scotland. The extra infrastructure required to accommodate this pattern of renewables deployment increases the cost of reinforcing the transmission network between Scotland and England and connecting offshore generators to the onshore grid. Moreover, the higher proportion of offshore development that takes place in the uniform scenario increases the non-infrastructure costs of developing new wind farms, and increases the total requirement for subsidy payments. Losses also increase significantly in the uniform case as power needs to be transported from generators located further north and further offshore to the main load centres. The increased need for DC reinforcements in the uniform scenario also increases losses.

In the wholesale power market, the main impact of introducing uniform generation TNUoS is to raise the cost of developing new generation capacity. In both the locational and uniform scenarios, demand growth and the retirement of existing coal-fired and nuclear generators will necessitate investment in new gas-fired generation capacity to provide mid-merit and peaking capacity. New gas-fired capacity will also be required to back-up the expected large scale deployment of intermittent wind generation. Removing the opportunity for new CCGT and OCGT projects in areas with negative TNUoS charges increases the cost of developing this new capacity and hence increases the level to which wholesale power prices need to rise before new investment is remunerated through the energy market. As we discuss in Chapter 6 this impact on power prices raises costs to consumers considerably.

6. Welfare Effects of Uniform TNUoS

In this chapter we estimate the welfare effects of replacing the existing locational charging regime with a flat uniform charge. We have defined two metrics for estimating the impact of uniform TNUoS: the impact on consumer bills and the impact on "avoidable" power sector costs, as we described below.

6.1. Impact on Consumer Bills

We estimate the impact on the consumer from the introduction on uniform TNUoS as the sum of the following components:[60]

- The change in the costs of purchasing electricity on the wholesale market, which we estimate from the change in the demand weighted average price over the year as projected by our power market model;
- The change in the costs of subsidising investment in new renewables generation, equal to the change in subsidy payments under the RO between the two scenarios;
- The change in transmission constraint costs and the costs of transmission losses,[61] both of which we assume are passed through to the consumer;[62] plus
- The change in revenue collected by the TSO through demand TNUoS charges.

Table 6.1 shows our estimated impact on consumers between 2011 and 2030, calculated in present value terms using a real discount rate of 3.5%, equal to the social discount rate recommended in HM Treasury's Green Book. The table shows that the total cost to consumers is £19.8 billion in real terms, or £3.56 per MWh of energy demand. Both these figures are presented as *additional* costs to consumers as a result of replacing the existing locational TNUoS with uniform TNUoS.

Around 70% of the £19.8 billion difference is due to the increase in prices in the wholesale power market caused by the increased cost of new entry. Transmission losses, which are 71% higher in the uniform scenario, account for 21% of the difference, and the increase in demand TNUoS charges, renewables subsidy costs and constraint costs account for the remaining 9% of the difference, so are small by comparison.

[60] We assume the price elasticity of demand is zero for this analysis.

[61] We value losses in this calculation at the demand weighted wholesale power price.

[62] We do not include charges for these items in our wholesale market model. Hence, we assume that they are either passed through to consumers through demand charges, or passed through to generators as a uniform variable charge per MWh in the case of constraint costs, or as uniform transmission loss factor in the case of losses.

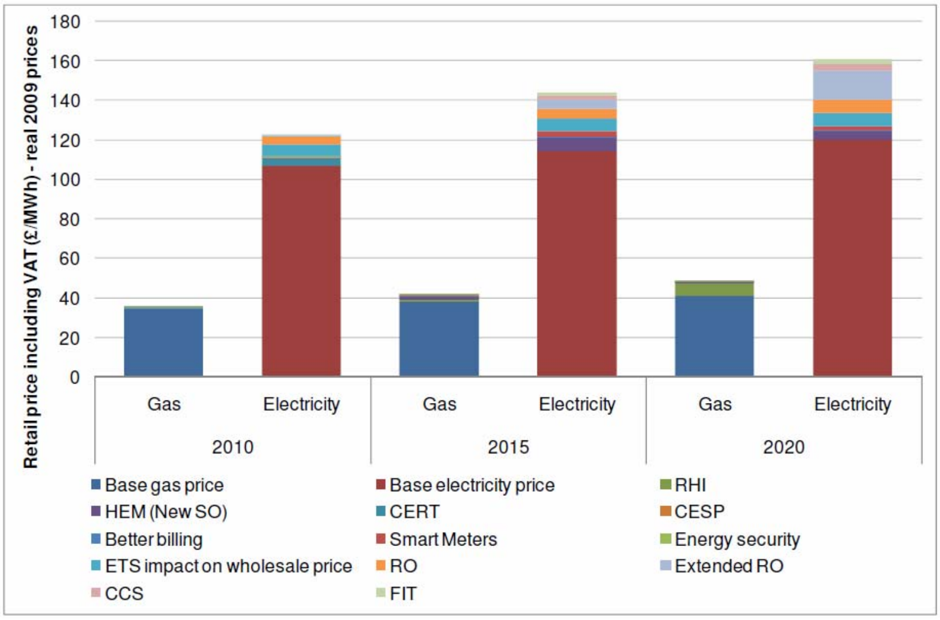
Table 6.1
Estimated Impact on Consumers (Real 2010 £)

NPV to 2030 @ 3.5%, 2010 Prices	**£Mn**	**£/MWh**
Wholesale Purchases	13,899	2.50
Renewable Subsidies	262	0.05
Losses	4,082	0.74
Constraints	344	0.06
Demand TNUoS Charges	1,181	0.21
Total	**19,768**	**3.56**

Source: NERA/Imperial Analysis

As Figure 6.1 shows, recent government projections suggest that the energy component of consumer bills in 2020 will reach £160/MWh in real 2009 prices. This suggests that our estimated impact on consumers from introducing uniform generation TNUoS would add around 2.2% to consumer energy prices in 2020.[63]

Figure 6.1
DECC Estimates of Customer Energy Costs



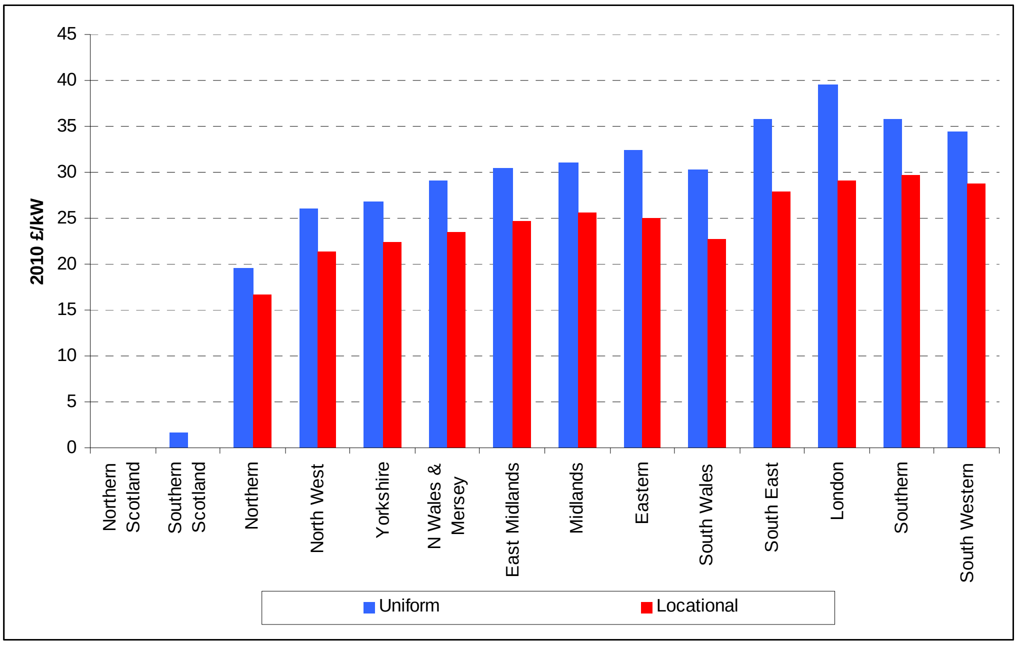
Source: Estimated impacts of energy and climate change policies on energy prices and bills, DECC, July 2010.

We would expect the increased costs of wholesale market purchases, renewables subsidies, constraints costs and losses to increase costs to consumers in all areas of the country.

63 £160/MWh in 2009 prices is equal to £162.5 in 2010 prices. £3.56 / £162.5 = 2.19%.

However, the increase in transmission system investment costs would be borne principally by consumers in the south of GB, as our projections indicate that Scottish demand TNUoS charges reach the "collar" of zero (or close to zero) in both scenarios.[64] Meanwhile, charges in the rest of GB would rise, so consumers in England and Wales will bear most of the impact from higher transmission investment costs as Figure 6.2 shows.

Figure 6.2
Avg Demand TNUoS Charges 2020-2030: Locational vs. Uniform (2010 £/kW)



Source: NERA/Imperial Analysis

6.2. Impact on Power Sector Costs

To examine the welfare impact of introducing uniform TNUoS charges, we estimated the change in power market costs as the sum of the following components:

- The change in fuel, CO2, O&M and construction costs incurred by non-renewable power generators, excluding the costs of TNUoS charges;
- The change in the costs of developing and operating new renewable generators;
- The change in transmission constraint costs and the costs of transmission losses; plus
- The change in the costs of transmission reinforcements.

Table 6.2 shows that the impact of uniform TNUoS on total power sector costs is £7.6 billion, or £1.36 per MWh of energy demand. Again, the figures shown in Table 6.2 are calculated as the additional costs of the alternative uniform scenario compared to the locational case.

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64 Under current charging arrangements, demand TNUoS charges cannot go negative.

Using this metric, the increasing cost of transmission losses accounts for 54% of the impact on the total costs of introducing uniform generation TNUoS charges. Additional transmission investment and constraint costs account for 20% of the impact, while costs in the generation segment of the market (including renewables) account for 26% of the impact.

Table 6.2
Estimated Impact on Power Sector Costs (Real 2010 £)

NPV to 2030 @ 3.5%, 2010 Prices	**£Mn**	**£/MWh**
Generation Costs	1,557	0.28
Renewables Costs	399	0.07
Losses	4,082	0.74
Constraints	344	0.06
Transmission Investment Costs	1,181	0.21
Total	**7,564**	**1.36**

Source: NERA/Imperial Analysis

Ofgem has estimated that around £32 billion of new investment will be required over the period to 2020 to upgrade British energy networks.[65] Our analysis indicates that moving to uniform generation TNUoS charges would add £1.3 billion to transmission system investment costs until 2020 (undiscounted), increasing the £32 billion investment requirement by 4%. Between 2020 and 2030 we estimate that the requirement for network reinforcement investment will be a further £0.5 billion (undiscounted) higher in the uniform case than the locational case. Hence, introducing uniform generation TNUoS would add £1.8 billion to the GB energy network investment requirement between 2020 and 2030, which to provide a sense of scale is around 6% of the £32 billion GB energy network investment requirement in the period to 2020.

6.3. Conclusion

In this chapter, we have estimated the total cost of introducing uniform TNUoS as between £7 and £20 billion, depending on the metric used. As we described in Chapters 4 and 5, our modelling suggests that uniform TNUoS would have a negligible impact on the evolution of power sector CO2 emissions to 2030, and that the target of 30% of renewables in power generation can be achieved in both cases. Hence, while we have identified substantial costs of introducing uniform TNUoS, we see no benefits of uniform TNUoS in helping to meet the government’s environmental targets.

To provide a further point of reference to compare against this estimated cost of uniform TNUoS, we surveyed a selection of recent government Impact Assessments (IAs) that

[65] Ofgem Reengineers Network Price Controls To Meet £32 Billion Low Carbon Investment Challenge, Ofgem Press Release, 26 July 2010.

identified policies with positive net benefits that the government subsequently adopted. For example, IAs for the mandated roll out of smart meters suggested net benefits of £2.2 billion and £4.8 billion,[66] the IA for the offshore transmission regulatory regime indicated net benefits of £0.9 billion,[67] and the IA for the introduction of BETTA showed net benefits of £0.08 billion.[68] In contrast, we estimate the net benefits of introducing uniform TNUoS, as measured by the change in power sector costs, would be negative £7.6 billion.

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66 (1) IA of smart/advanced meters roll out to SMEs, DECC, 2009; (2) Mandated roll-out of smart meters under the competitive model by the end of 2020, DECC, 2010.

67 Impact Assessment of the Offshore Electricity Transmission Regulatory Regime, DECC, 2009.

68 British Electricity Trading and Transmission Arrangements: Regulatory Impact Assessment, DTI.

7. Summary and Conclusions

The British electricity system needs major investment in new generation and transmission capacity over the next two decades to meet the government's green targets and ensure security of supply. On the generation side, this investment includes a requirement for massive expansion of renewables and other low-carbon generation, as well as major new investment in gas-fired plant – our own estimates are that GB needs 30GW of new low-carbon generation and 33GW of new gas-fired investment by 2030. For both these types of investment, investors have a wide choice of where to locate their plant, and the choices made by investors will have significant implications for the cost of generation and transmission investment, as well transmission congestion and losses.

Hence, in this report, we have assessed the impact of replacing the current system of locational TNUoS charges for GB power generators with a system of uniform charges. We have examined the impact on the wholesale power market, renewables investment incentives, and transmission system costs and estimated changes in avoidable costs, and changes in customer bills over the period to 2030.

7.1. Summary of Modelling Results

In the locational scenario, we predicted that generation TNUoS charges in Scotland will increase, while charges in England and Wales will fall. The impact of these locational charges is to encourage new investment in conventional thermal generation capacity in the south of England and Wales, close to the areas of net demand in the south east of England. In contrast, in the uniform case NTS charges provide the main locational incentive for new generation, and new gas-fired generators locate close to NTS entry terminals in Scotland and to some extent in south Wales and along the east coast England.

Our analysis also indicates that the locational charging regime incentivises investment in new wind capacity across the whole of GB, with offshore development concentrated in the south west of England, on the Dogger Bank, and along the west coast of Scotland. Most onshore developments take place in Scotland in the locational scenario, including some development on the Scottish islands, although around 3GW of onshore wind development takes place in England and Wales.

In the uniform scenario, the ability to avoid local asset charges incentivises wind development further offshore and in more remote onshore locations where developers can obtain higher load factors. Uniform TNUoS charges also reduce the scale of wind development in the south of England and in Wales, which is largely displaced by investment in onshore wind generation in Scotland.

The extra renewable and conventional generation capacity developed in Scotland and the north of England under the uniform charging regime increases the costs of reinforcing the transmission network and the costs of transmission losses. We estimate that these effects will increase the costs of operating and developing the GB transmission system by between £7.9 and £9.8 billion over the period to 2030 in present value terms.

In the wholesale power market, the main impact of introducing uniform generation TNUoS is to raise the cost of developing new generation capacity, such as the new gas-fired capacity that will be required to back-up the expected large scale deployment of intermittent wind generation. Removing the opportunity for new CCGT and OCGT projects in areas with negative TNUoS charges will increase the cost of developing this new capacity and hence increase the level to which wholesale power prices will need to rise before new investment is remunerated through the energy market.

7.2. Comparison of the Charging Models

These modelling results indicate that the current model for generation TNUoS charging[69] incentivises generation to locate in transmission charging zones situated close to the areas of net demand in the south of GB. We obtain this result essentially because charges reflect the investment costs caused (or avoided) through the addition or removal of generation capacity from a particular transmission zone.

Also, the current charging regime, and the use of local asset charges in particular, incentivises new wind generators to make a trade-off between the load factors achievable in an area and the costs of connecting to the transmission system. If these local asset charges were removed (or capped) new wind generators would have a strong incentive to locate in the areas with the highest load factors irrespective of the infrastructure costs they impose on the system. In contrast, the removal of cost-reflective signals from transmission pricing means generators ignore the costs they impose on the transmission system (or the costs their presence on the system allows the TSO to avoid) in making their locational decisions.

Our modelling also indicates that in the face of significant changes facing the electricity industry in coming years, such as increasing intermittency and an increasing proportion of generation located offshore, the locational charging regime we defined continues to incentivise a more efficient placement of new generation capacity on the transmission system than the uniform charging scenario. Locational TNUoS charges continue to approximate the incremental (or decremental) cost of reinforcing the transmission system due to the presence of generation capacity in a given zone.[70] Our modelling also suggests that government renewables and CO2 reduction targets are achievable in the locational scenario. For these reasons, and because the alternative uniform regime reduces welfare so substantially, we consider that the current regime is sustainable over the period to 2030.

However, these conclusions hinge on the comparison between the current generation TNUoS regime and the alternative of uniform charging. Other transmission charging models such as locational marginal pricing for example, may provide even stronger signals for generators to locate efficiently on the transmission system. If we had examined such “more locational” charging models, we may have found that they reduce costs (i.e. increase overall welfare) compared to the locational case we examined by incentivising more efficient behaviour by generators. Comparing against “more locational” alternatives would therefore also have increased the estimated cost of uniform charging.

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69 We obtained this result by making only limited assumptions regarding how the existing locational TNUoS charging regime will evolve over time, as we describe in Chapter 3.

70 The levels of incremental reinforcement costs change over time due largely due to our assumption that the Scotland-England boundary will be reinforced using offshore HVDC cables.

Even without fundamental reform of the current transmission charging arrangements, it may be possible to improve the cost reflectivity of the signals sent to generators through locational TNUoS charges. For example, due to increasing wind penetration, transmission investment costs going forward may be increasingly driven by off-peak conditions rather than peak demand conditions. Hence, reforms of the current transmission charging regime to better reflect the costs generators impose on the system in off-peak conditions may further improve the efficiency of their locational decisions and reduce overall costs as a result.

7.3. Conclusion

Our analysis demonstrates that moving to a uniform TNUoS charge would incentivise investment to locate in more remote parts of GB where, for example, load factors for wind generation are highest and access to gas is cheapest. We estimate this change in investment patterns would substantially increase generation and transmission costs in GB, resulting in a net cost to consumers of £20 billion in NPV terms relative to a system with locational generation TNUoS, and an increase in costs of £8 billion in NPV terms.

Because in some areas we could not objectively define assumptions using government or other published sources, we took a “conservative” approach of selecting modelling assumptions. This indicates that our estimated difference in costs between the locational and uniform charging models of £8 billion to £20 billion may be an underestimate. For example, our assumptions that transmission reinforcements come online when it is efficient for them to do so, the assumption of zero bid-offer spreads into the balancing mechanism and our relatively low assumed cost of transmission reinforcements all suggest we may have understated the impact of uniform TNUoS on constraint costs.

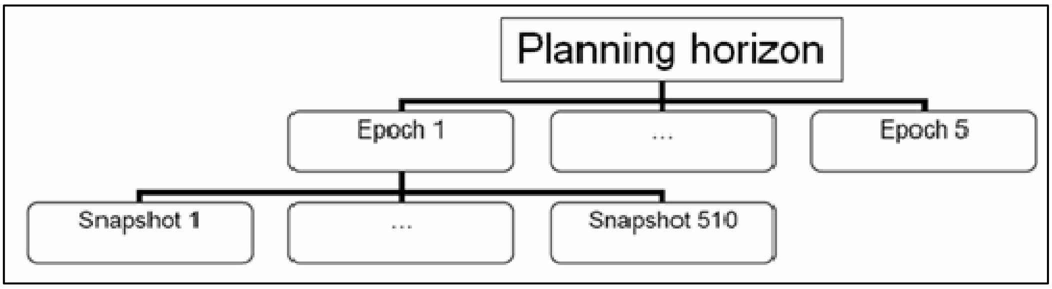
At the same time, we find no significant difference in performance between the two charging regimes in terms of CO_2 emissions and the achievement of the UK target for 30% of renewables in electricity consumption by 2020. Hence, we conclude that a move to uniform TNUoS would lead to a significant increase in costs without any discernable benefits.

Appendix A. Description of DTIM

A.1. Epochs

Throughout an epoch the generation capacity is assumed to be static, whereas generation fuel costs and availabilities can be varied seasonally. Each epoch consists of a number of representative snapshots.

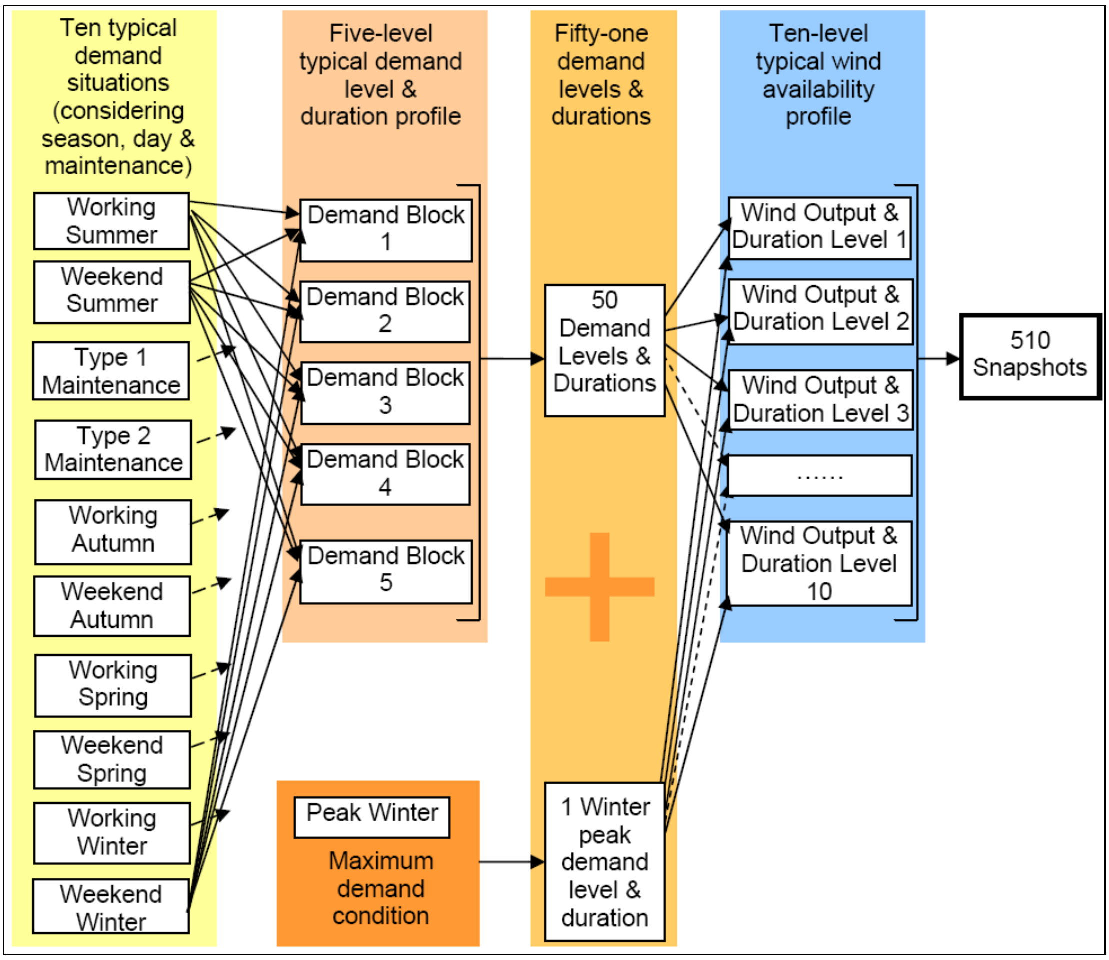
Figure A.1
DTIM Epochs



Source: Imperial College

The 510 snapshots are obtained by combining 51 demand levels with 10 wind output levels. Of the 51 demand levels (each has its duration specified), one of them is winter peak demand level, and the rest 50 are derived from 5 daily demand blocks applying on 10 typical days. The 10 typical days are working days and weekends for winter, spring, summer, autumn and boundary maintenance seasons respectively. In addition, the boundary maintenance days can represent the demand levels of any season specified by the user. The demand levels were then re-adjust to take into account any intermittent embedded generation including PV and hydro.

Figure A.2
DTIM Snapshot Definitions



Source: Imperial College

A.2. Boundaries and Zones

As described earlier the DTIM system consists of 16 zones, 15 transmission boundaries and 2 DC links.

- DTIM boundaries TB1 to TB6 equate to SYS boundaries 1-6.
- DTIM boundary TB7 is mapped to a non-SYS boundary, known as B7a, which runs South-of-Penwortham rather than South-of-Harker.
- DTIM boundary TB8 is a non-SYS boundary to North Wales, namely West of Deeside and West of Treuddyn.
- DTIM boundary TB9 is mapped to the Humber Estuary boundary, namely East-of-Keadby and cuts across Thorton--Creyke Beck circuit.
- DTIM boundary TB10, TB13 and TB15 are SYS boundaries B8, B9 and B15 respectively.
- DTIM boundary TB11 is south Wales boundary, namely West-of-Walham plus West-of-Melksham.

- DTIM boundary TB12 can be mapped to East Anglia., ie. transmission zones Norwich Main, Sizewell and Bramford.
- DTIM boundary TB14 maps to the boundary to Cornwall, Devon and Somerset (NGET FLOP zones F and E). that's SYS boundary B13, SYS zone Z13.

The initial capacities and thickness of each transmission boundary are given below:

Table A.1
DTIM Transmission Boundary Characteristics

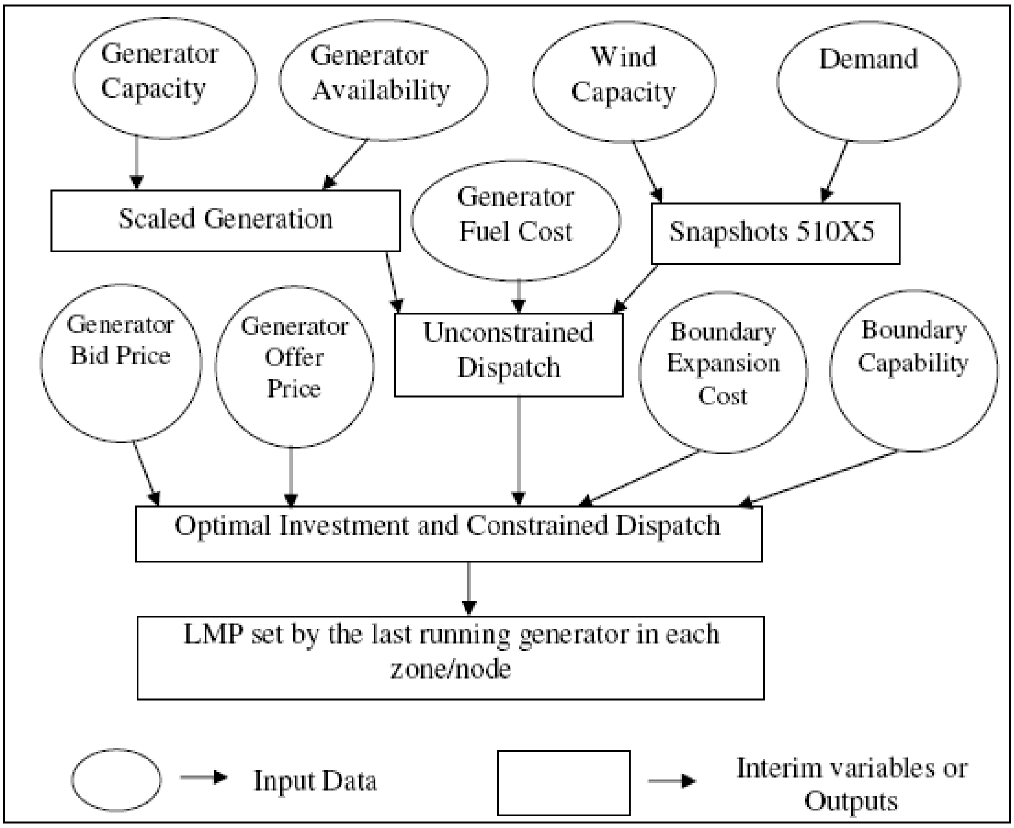
Transmission corridor	2010 Transfer Capability (MW)	Distance (km)
SHETL- North West	400	60
SHETL- North to South	1600	100
SHETL- Sloy Export	210	50
SHETL – SPT	1550	120
SPT- North to South	2618	35
SPT – NGET	2200	150
NGET - Upper North – North	3573	150
NGET - North Wales	3000	79
NGET- Humber	5500	40
NGET- North to Midlands	10000	93
NGET- South Wales	3500	75
NGET- East Anglia	2800	80
NGET- Midlands to South	10000	155
NGET- South West	3477	195
NGET- Estuary	5000	60
HVDC East Coast	0	330
HVDC West Coast	0	280

Source: Imperial College

A.3. DTIM Inputs and Outputs

The DTIM required inputs and outputs as well as the modelling process is summarised below:

Figure A.3
DTIM Inputs and Outputs



Source: Source Imperial College/National Grid

Appendix B. DTIM Gone Green Scenario

The National Grid Gone Green Scenario was used to calibrate the DTIM transmission investment costs. The generation and demand inputs that we used were the following:

Table B.1
Gone Green Generation Inputs

Technology	Y2008 [MW]	Y2013 [MW]	Y2018 [MW]	Y2025 [MW]	Y2029 [MW]
Wind	1,480	8,091	20,713	34,207	38,807
Nuclear	10,424	9,444	6,013	9,653	10,550
Marine	0	0	610	2,410	4,310
Base_Gas	14,953	18,181	15,195	16,414	17,838
Base_Coal	15,892	13,673	14,402	10,753	9,020
France	1,988	1,988	1,988	1,988	1,988
Other Renew	45	576	776	1,076	1,376
Water	1,081	1,129	1,129	1,129	1,129
Marg_Gas	11,573	13,424	16,925	10,905	9,835
Marg_Coal	12,481	11,727	6,398	3,146	1,916
Pump_Stor	2,744	2,744	2,744	2,744	2,744
Peakers	4,640	4,540	3,832	5,203	5,914

Source: National Grid

Table B.2
Gone Green Demand Inputs

	Peak Demand [MW]	Energy [MWh/Epoch]
Epoch 1 / 2008-2010	60,300	1,065,000,000
Epoch 2 / 2011-2015	61,300	1,780,000,000
Epoch 3 / 2016-2020	61,300	1,765,000,000
Epoch 4 /2021-2028	59,900	2,768,000,000
Epoch 5 / 2029-2030	59,500	688,000,000

Source: National Grid

Appendix C. Defining the Locational Scenario

- **Intermittent generation charging**

Currently, the transport model considers peak conditions for charging by scaling generation transmission entry capacity (TEC) to peak demand reflecting the SQSS planning philosophy. Moving to a generation mix with significant intermittent generation, peak power flows and constraints are likely to be associated with high wind off-peak conditions, which are not captured by the charging scenario.

Furthermore, the scaling of TEC does not take into account the load factors of different generation technologies during the peak scenario, assuming 100% contribution for every plant. This assumption is unrealistic when it comes to intermittent generation and National Grid launched GB ECM 25 to review this issue and a methodology was proposed combining two scenarios with different load factors for different technologies, reflecting partially the Cost Benefit Analysis approach, considered under the SQSS review. Nonetheless, given the objectives of Project TransmiT and the industry response, it was announced that GB ECM 25 will not be pursued further and it will be explicitly addressed by Project TransmiT.

We could not objectively assume that the GB ECM 25 methodology would be taken forward after the conclusion of Project TransmiT or devise an alternative method that might affect significantly locational TNUoS charges. Consequently, we have assumed that the charging arrangements for intermittent generation will be kept as they are at present.

- **Offshore Generation Charging**

As it stands, offshore generation charges are broken down as follows:

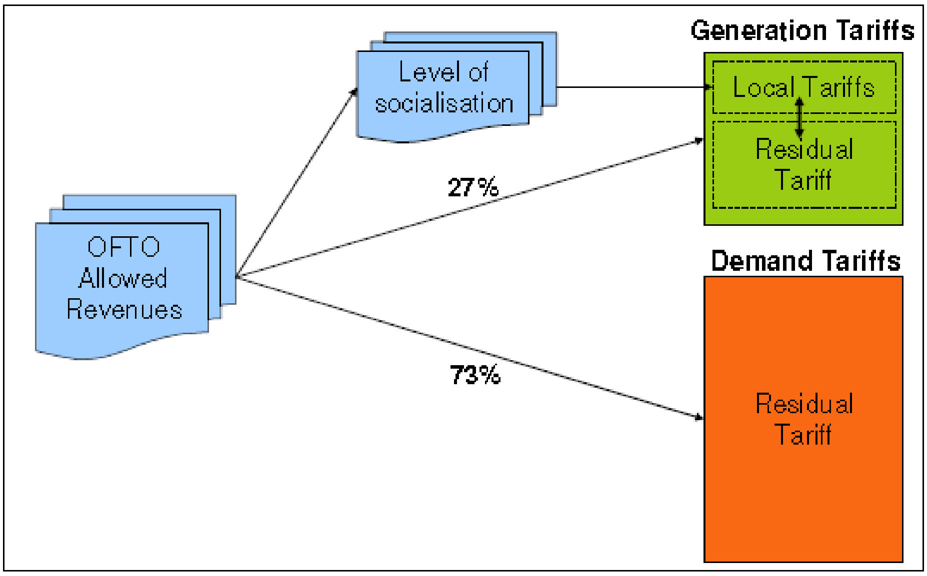
- Circuit charges (Cable, Reactive Compensation & HVDC converters);
- Substation charges (Transformer, Switchgear &Platform);
- Wider charges (TNUoS at onshore connection point); and
- The residual charge.

Whether the circuit and substation are defined as local or wider assets is particularly important given that under the current charging methodology local asset charges are targeted to local generators. Following the offshore transmission charging review GB ECM 08 it was decided:

- All local asset costs will be charged to offshore generators;
- Any difference between OFTOs’ revenue requirements and revenue from local charges (e.g. due to spare capacity) will be socialised through generation TNUoS charges; and
- Similar arrangements will appliy offshore to those already applicable to onshore generation, including onshore local circuits.

There are two issues that arise from the above, namely the level of cost socialisation and the relationship between the local charges for the offshore grid and the TNUoS residual charge.

Figure C.1
Offshore Transmission Costs Allocation



Source: National Grid

The socialised costs of offshore transmission are recovered through the residual element of the TNUoS applying the 27/73 split. National Grid projections of the level of socialisation vary between 10% and 45% of total cost and the exact level will depend on the site transmission planning and the generation connection pattern. For this assignment, we assumed that for each offshore development the transmission system would be optimally sized and that generators would pay the costs of this infrastructure through a charge in £ per kW of generation connected to the OFTO.

The other critical issue we identified arises from the fact that offshore local asset charges contribute to the 27% of transmission revenue that under current arrangements if recovered through generation charges. The total charges of generation are computed as follows:

TNUoS Generation Charges = *Local Asset charge* +
Wider Locational TNUoS charge +
TNUoS Residual Charge

The residual may be positive or negative depending on whether the Local Asset and Wider Locational TNUoS charges have recovered less or more than the total generation revenue requirement. In a system with significant offshore transmission investment the generation local asset charge might become high enough so that the generation residual becomes very negative and the demand residual increases proportionally. Although the locational differentials of the charges would be preserved this feedback loop might distort transmission price signals, e.g. by making wider TNUoS charges in all zones negative. This issue might need further consideration under Project TransmiT but for the purposes of this project we have assumed that the current arrangements will be preserved.

- **HVDC links charging**

DTIM optimises the investment and capacity of the Western and Eastern HVDC links (multiple links if needed) as they have been defined in the ENSG report. Since the power flows through these cables are controllable and do not depend on their relative impedances, it is unclear how power flows, and hence charges, should be computed.

National Grid has proposed two methodologies:

- **Required capacity option:** first maximise the power flow on the AC network (up to its maximum capability) before utilising the HVDC links for the remaining required power flow arising out of the generation and demand assumptions; and
- **Locational security factor option:** recalculate the locational security factor, which is currently done as an average across GB, specifically for the circuits connecting Scotland to England to properly reflect the cost of the HVDC in TNUoS charges.

We reviewed both methodologies and decided to implement the required capacity option given the uncertainty in changes of the locational security factor. Consequently, for every modelling year we used DTIM to compute the power flow of the DC links. We included the DC links in the Transport model as underground cables and iteratively computed an equivalent impendence so as to obtain the required power flows, and repeated this exercise for every year.

- **Interconnector charging**

According to EU regulations, interconnectors should not be classified as generation or load and thus not be subject to transmission charges. We account for this rule when rolling forward TNUoS charges to 2030. However, for our load flow modelling we treat interconnectors like any other generator in order to compute investment requirements and constraint costs.

- **Island charging**

Island charging arrangements are still under consultation and the main issue is whether the assets connecting the islands with the Main Interconnected Transmission System (MITS) will be treated as local assets or whether there will be some cost socialisation. Given the similarities of island interconnections with the offshore transmission system, we treated them in a similar way and thus assume that island generators would be exposed to the full cost of the interconnectors.

- **Embedded generation charging**

Currently embedded generation is treated as negative demand and thus receives/pays negative demand charges, which due to the residual are positive in all zones. National Grid recognises that there is a significant benefit of embedded generation in terms of distribution system savings but that the current charging arrangements, given the 27/73 generation/demand split and the residual element, are not appropriate.

Two alternative methods have been proposed for charging embedded generation, namely the Gross Supplier Agency Model (GSAM) and the Net DNO Agency Model and although we recognise there are merits with both approaches, given the regulatory uncertainty we decided to continue treating embedded generation as negative demand and thus assume that they pay negative demand TNUoS.

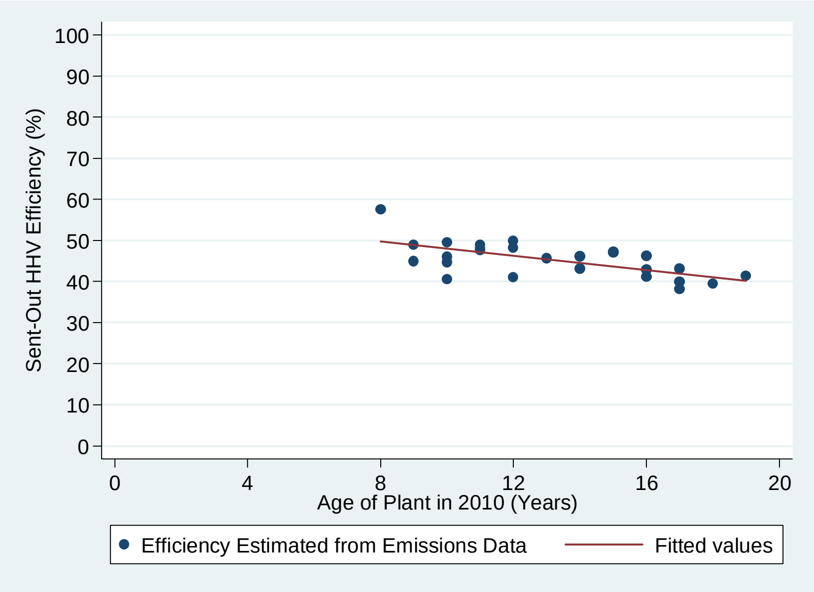
Appendix D. Technical Generation Assumptions

D.1. Thermal Efficiencies

We defined our assumptions regarding the thermal efficiencies of existing thermal generators in GB from our analysis of historic CO2 emissions and power production.[71]

For gas-fired CCGTs, we have found a strong correlation between efficiencies and the age of the unit (see Figure D.1) reflecting, amongst other things, technological progress in CCGT technology. Given the noise in the dataset, we started with Mott McDonald's estimate of the efficiency of a new entrant CCGT (51.9%, HHV sent-out), and we used the slope of the line shown in Figure D.1 to define the differences in efficiencies between different generations of gas-fired CCGTs.

Figure D.1
Efficiencies of GB CCGT Plants



Source: NERA/Imperial Analysis

We used the same method to estimate the efficiencies of coal fired generators, except rather than using the Mott MacDonald estimate as the benchmark, we used the efficiency of Drax, which we estimate is the most efficient coal plant on the GB system. For other technologies, we assigned each unit a "generic" efficiency for each technology, which we will define using the NAP emissions and power production database, or Mott MacDonald (2010).

[71] Our analysis used CO2 emissions and power production data between 1998 and 2003 from the UK National Allocation Plan databases.

D.2. Dynamic Constraints and Unit Commitment Costs

We used data from the Balancing Mechanism Reporting System (BMRS) to define assumptions on GB generators' dynamic constraints (minimum up/down times and minimum stable generation).

Our model also requires data on the start-up costs, and in particular the fuel consumed during start-up. To estimate the fuel consumed during start-ups for each generation technology installed in GB, we used the "validated" dataset published each year by the regulatory authorities in the Republic of Ireland and Northern Ireland. Our assumptions for existing CCGTs, coal and oil-fired STs and OCGTs reflect the average of all plants using these technologies that are currently installed on the Irish system.

Following the assumptions in Mott MacDonald (2010), we assumed that any new CCGTs built in GB will be configured as multiple units of single shaft blocks (1 GT coupled on the same shaft to 1 ST), and the characteristics we assumed for new CCGTs are based on a similar unit already installed on the Irish system. We understand that this configuration provides more flexibility than alternatives, and may be desirable in the face of the expected growth in intermittent generation.

D.3. Outage Rates

We applied the following outage rates to existing thermal generators in the British market:

- For existing coal-fired power stations, we assumed an average planned outage rate of 14% and an average forced outage rate of 9%, based on our analysis of the performance of a range of GB coal plants. Our total outage rate assumptions for GB coal plants ranges from 10% to 34%, depending principally on the age of the plant;
- For CCGTs, we assumed a planned outage rate of 7% and a forced outage rate of 3% based on data from the North American Electric Reliability Council (NAERC); and
- For OCGTs, we assumed a planned outage rate of 4% and a forced outage rate of 3% based on data from the NAERC.

D.4. Operating and Maintenance Costs

The starting point for our operating cost assumptions was the fixed and variable O&M cost estimates for new entrant CCGTs, coal plants and OCGTs in the Mott MacDonald (2010) "medium" case.[72] However, we have deviated from Mott MacDonald in the following respects:

[72] We assume that Mott McDonald's estimates represent average O&M costs over the lifetime of a plant. Hence, we assumed that existing plants face the same operating costs as new entrants. In practice, the operating costs of a plant tend to evolve over its lifetime, and may depend on the configuration and condition of a plant, for example. However, as we do not have access to detailed cost information of individual plants, we cannot account for such differences objectively.

- **Network Charges:** We took existing gas transmission charges from National Grid's latest charging statement. We used the DTIM and TNUoS charging models to predict TNUoS charges, as described in Section 2.1.
- **Business Rates:** We defined assumptions on the business rates paid by power generators in light of discussions we held with the Valuation Office Agency (VAO). We understand from these discussions that coal-fired generators pay business rates of between £7-9/kW, gas-fired generators pay between £9-10/kW and wind generators pay around £25/kW.
- **Land Costs:** Mott McDonald's analysis excludes the cost of land used for power generation. We therefore estimated the cost of industrial land using data from the VAO,[73] and added the rental charges to annual fixed O&M costs. We assumed that a 2,000MW coal plant would require 1 square kilometre of land, and that an 800MW CCGT would require 0.2 square kilometres of land.[74] We scaled these land requirements by the installed capacity of each generator.
- **Biomass Co-firing:** In addition to the costs of procuring coal and operating a coal plant, some existing coal-fired generators may face additional costs and earn revenues as a result of co-firing biomass. In the long-run we assumed that subsidy mechanisms, such as the RO, will be structured to provide coal generators with a payment that only just incentivises them to co-fire biomass with coal. Hence, for modelling purposes we assumed that the net impact on their O&M costs from co-firing biomass will be zero.

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73 See slide 14 of our kick-off meeting presentation.

74 To derive this assumption, we examined aerial photographs of several existing GB generators to estimate approximate land requirements.

Appendix E. Renewables Assumptions

To define inputs into our renewables investment model, we defined assumptions on the costs of developing and operating onshore and offshore wind generators, which we summarise in this appendix.

E.1. Onshore Wind

E.1.1. Costs

We used cost information from the “medium” case in Mott MacDonald (2010) to form our assumptions on the costs of developing onshore wind turbines. However, we deviated from Mott MacDonald (2010) in the following areas:

- **Business Rates:** Following our discussions with the VAO, we assumed that wind farms pay a uniform charge of £25/kW in business rates.
- **Network Charges:** We used our DTIM model and the TNUoS charging model to predict TNUoS charges, as described in Section 2.1.

E.1.2. Load factors and production profiles

Our approach to defining locational load factor assumptions combines data on average annual wind speeds in different part of the country from the DECC wind speed database, and a mathematical relationship between average wind speed and expected load factors.

First, we estimated a mathematical relationship between the average load factor of offshore wind sites and the “wind power” of a site using data from the Carbon Trust (2008).[75] This relationship is represented by the red line in Figure E.1. The figure also shows the range of annual load factors we estimate for existing onshore wind generation sites.[76]

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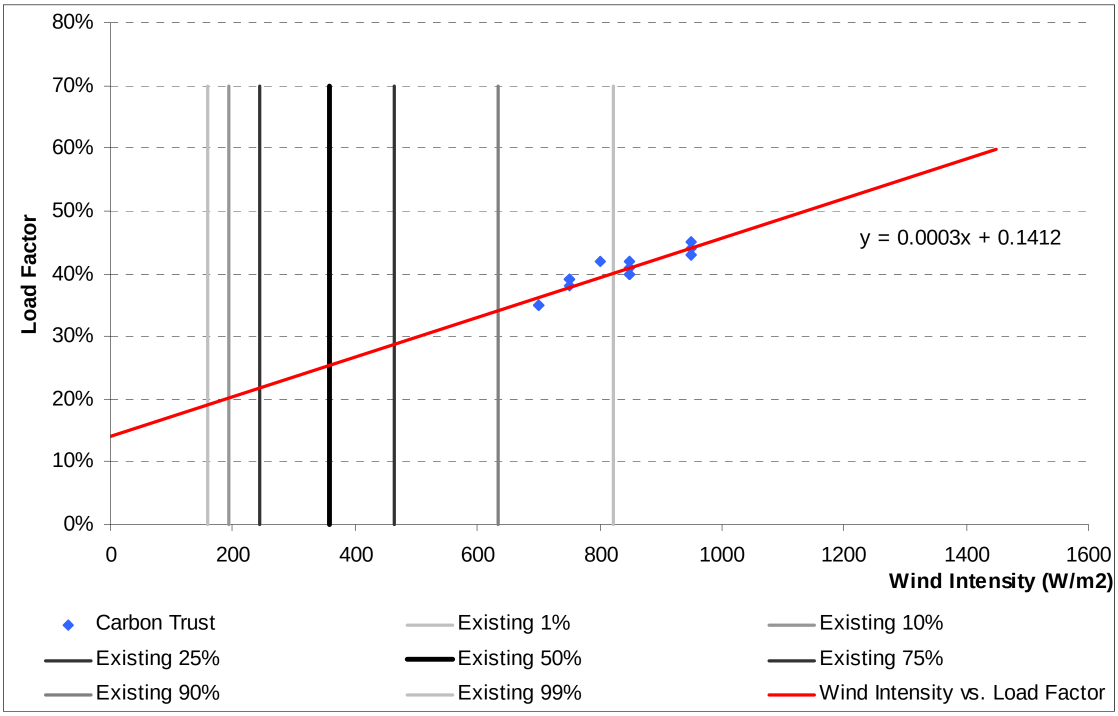
[75] Offshore wind power: big challenge, big opportunity - Maximising the environmental, economic and security benefits, the Carbon Trust, 2008, Chart A1.

[76] See the vertical lines that illustrate the percentiles of the distribution of the load factors we estimate for onshore wind farms, e.g. the intersection of the “existing 50%” line with the “wind intensity vs. load factor” line at a load factor of 25% indicates that we estimate 50% of onshore wind farms have a load factor below 25%.

Figure E.1
Wind Power (watts / m²) vs. Average Load Factor



Source: NERA/Imperial Analysis of data from the Carbon Trust (2008) and DECC

Then, using a regression equation, we observed that approximately half of the variation in these wind load factors can be explained by their position in the country from north to south and from west to east, with the highest load factors in the north west and the lowest in the south east, as the regression equation in Table E.1 illustrates.[77] This relationship is also illustrated in Figure E.2, which shows that average annual wind speeds rise on average the further north a site is from Cornwall, and fall the further east a site is from Cornwall.

We used this regression equation to estimate wind speeds in each transmission zone within GB, and converted these into load factors using the relationship illustrated in Figure E.1. This procedure defined our assumptions on the average load factor achievable for onshore wind sites across each region of GB, with each region defined by generation TNUoS zones.

[77] The regression equation has an R-squared of 0.48, which indicates that 48% of differences in wind speeds (and hence load factors) across sites in GB can be "explained" statistically by differences in their position in the country from north to south and from east to west.

Table E.1
Regression Equation (% Load Factor vs. Distance North/East)

	Coefficient	Standard Error	t-statistic
Constant Term	0.29	0.02	16.48
Distance North of Cornwall (km)	0.00	0.00	10.46
Distance East of Cornwall (km)	0.00	0.00	-7.55
Observations	230		
R-squared	0.48		

Source: NERA/Imperial Analysis

Figure E.2
Annual Wind Speed vs. Distance from Cornwall (North/South & East/West)

Source: NERA/Imperial Analysis of data from DECC

However, we also accounted for the diversity of wind sites that in practice exist within each region of GB. First we used the regression equation in Table E.1 to estimate the average (or expected) load factor in each region of GB. We then used the residuals from the regression to estimate the proportion of wind sites that would provide load factors different from the average by plus/minus 5%, and plus/minus 10%. By applying this procedure, we have assumed that in all regions of GB there is a mix sites where wind projects could achieve relatively high and relatively low load factors, albeit load factors will on average be highest in the north west, and lowest in the south east.

To "shape" these load factors over the year, we used data from the Balancing Mechanism Reporting System (BMRS) provided by RWE on the half-hourly output of existing onshore wind sites. We then "shifted" these profiles of production up or down to achieve the annual load factors indicated by local wind speeds to forecast the pattern of production of onshore wind farms in specific parts of the country.

E.1.3. National build rates and resource potential by 2020

For onshore wind sites, we assumed an annual maximum build rate of 1GW per annum. By 2020, this leads to a maximum onshore wind potential of around 14GW. In summary, the evidence to support the use of a 1GW/annum build rate for onshore wind is as follows:

- Renewables UK estimates that 900-1,000MW per year of onshore wind can be developed in 2012 and 2013 from 39 projects.[78]
- This build rate is below the rates achieved in Germany and Spain over the preceding decade,[79] which indicates that supply chain constraints will not necessarily prevent its achievement;
- The rates of planning approval for onshore sites have averaged around 0.9GW per year between 2004 and 2009;[80] and
- It is similar to the build rate that a study by Poyry for the Committee on Climate Change (CCC) indicated was feasible over the period to 2020 if proposed improvements to the planning and transmission access regimes are "*effective and timely*".[81]

We defined our assumptions on the total resource potential by region in 2020 based on the "higher" case presented in SKM (2008), as shown in Figure E.3. We have used the higher case as we are trying to identify *potential* resource, rather than estimate what capacity is *likely* to be developed.

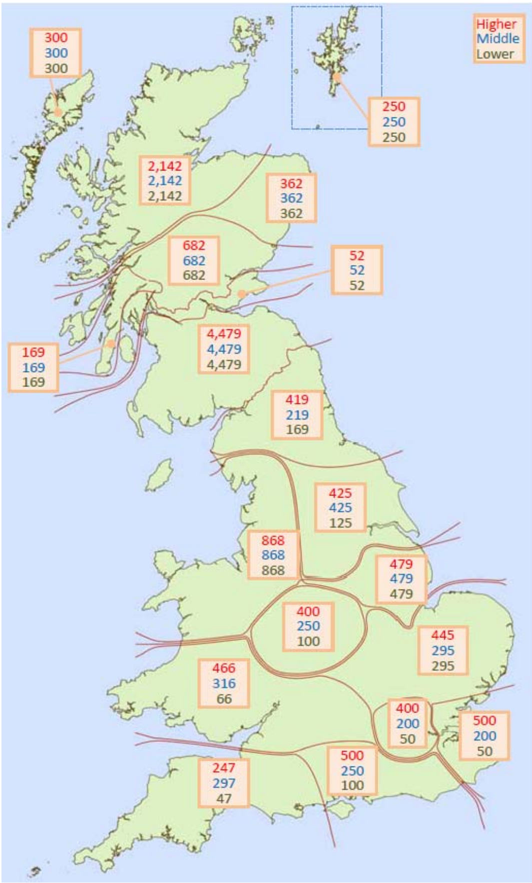
78 State of the Industry Report: Onshore and offshore wind: a progress update, November 2010.

79 Memorandum submitted by the British Wind Energy Association, House of Commons Energy and Climate Change Select Committee (2008-9) Low Carbon Technologies in a Green Economy, cited in 2050 Pathways Analysis, DECC, July 2010, page 186.

80 NERA analysis based on: 2050 Pathways Analysis, DECC, July 2010, Figure I1.

81 Timeline for Wind Generation to 2020 and a set of progress indicators, Pöyry prepared for the CCC, July 2009, page 4 and figure 2.

Figure E.3
Wind Resource by Region



Source: SKM (2008)[82]

E.1.4. National build rates and resource potential by 2030

In the period to 2030, the overall potential for onshore wind becomes increasingly uncertain. However, over this timeframe, there may be more scope for the supply chain to expand to increase the annual rate of wind deployment. Hence, from 2020 onwards we assumed the maximum annual build rate for onshore wind will increase from 1GW to 1.6GW, based on the assumptions in DECC's "level 3" pathway for onshore wind.[83] This assumption would also cap the total development of onshore wind capacity to 30GW, which is approximately equal to the range of 28-31GW of "practical resources" that DECC estimates could be developed in the UK.[84]

We allocate the total wind potential across GB in the period 2020-2030 using the same ratios as in the period to 2020 (see Figure E.3).

82 Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks, BERR Publication URN 08/1021, SKM, June 2008. Figure 4.2.

83 NERA analysis based on: 2050 Pathways Analysis, DECC, July 2010, page 187.

84 2050 Pathways Analysis, DECC, July 2010, page 184.

E.2. Offshore Wind

E.2.1. Turbine, tower and foundations costs

The costs of developing offshore wind turbines fall into the following main categories:

- Infrastructure and grid connection costs;
- The cost of turbines and towers;
- Foundations costs; and
- Licensing and planning costs.

Having conducted a review of published literature on the costs of developing new wind generation capacity and through our discussions with RWE, we understand that the costs of turbines and towers and licensing and planning do not differ significantly with the distance from shore or the depth of the seabed. However, foundations costs depend mainly on seabed depth, and infrastructure and grid connection costs depend largely on distance from shore.

As for onshore wind and for conventional generation costs, we used the Mott MacDonald (2010) "medium, n^{th} of a kind" estimates of turbine and tower costs at all offshore sites.

Because the "round 1" and "round 2" sites are all relatively close to shore, and hence we assumed they are all in areas with a relatively shallow seabed, we do not make any further adjustments to Mott McDonald's cost estimates of turbine, tower and foundations costs. However, the depth and distance from shore of the "round 3" sites differ considerably across the various proposed developments.

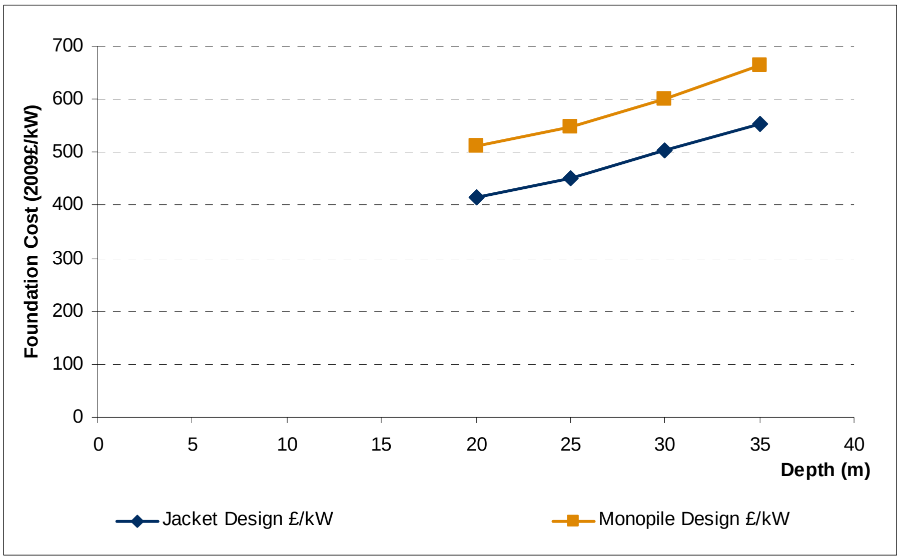
As the Mott MacDonald "round 3" cost estimates assume a depth of 50 metres,[85] we adjust the Mott MacDonald costs by £9/kW/metre of seabed depth either above or below this level, corresponding to the slopes of the lines in Figure E.4.[86] For example, as we show in Table E.2 and Table E.3, we would add £90/kW to Mott McDonald's cost estimate for a project developed at a seabed depth of 60 metres.

Figure E.5 shows the range of costs of developing projects in a range of offshore sites we estimate using this procedure.

85

86 Calculated on the basis of foundation costs by Ramboll (2009) for "jacket and monopole" foundations.

Figure E.4
Seabed Depth vs. Foundation Cost



Source: NERA/Imperial Analysis of data from Ramboll[87]

Table E.2
Depth Adjustments to Construction Costs, Round 3

Wind farm	Region	Availability MW	Depth (m) Min	Max	Average	Delta vs Depth Benchmark (m)	Construction Cost Adjustment (£/kW)
Bristol Channel	South West	1,500	23.0	56.0	39.5	-10.5	-95
Dogger Bank	North Sea	9,000	40.5	63.0	51.8	1.8	16
Firth of Forth	Scotland	3,500	50.0	80.0	65.0	15.0	136
Hastings	South	600	27.6	62.0	44.8	-5.2	-47
Hornsea	North Sea	4,000	35.0	40.0	37.5	-12.5	-114
Irish Sea	Irish Sea	4,200	53.0	78.0	65.5	15.5	141
Moray Firth	Scotland	1,300	43.5	57.0	50.3	0.3	2
Norfolk Bank	Southern North Sea	7,200	37.5	70.0	53.8	3.8	34
West of Isle of Wight	South	900	42.1	56.3	49.2	-0.8	-8

Source: Depth data from the Crown Estate.[88] Benchmark depth for Round 3 developments is 50m.

87 Kriegers Flak Offshore Wind Farm, Jacket and Monopile Foundation Study 2008-2009, March 2009.

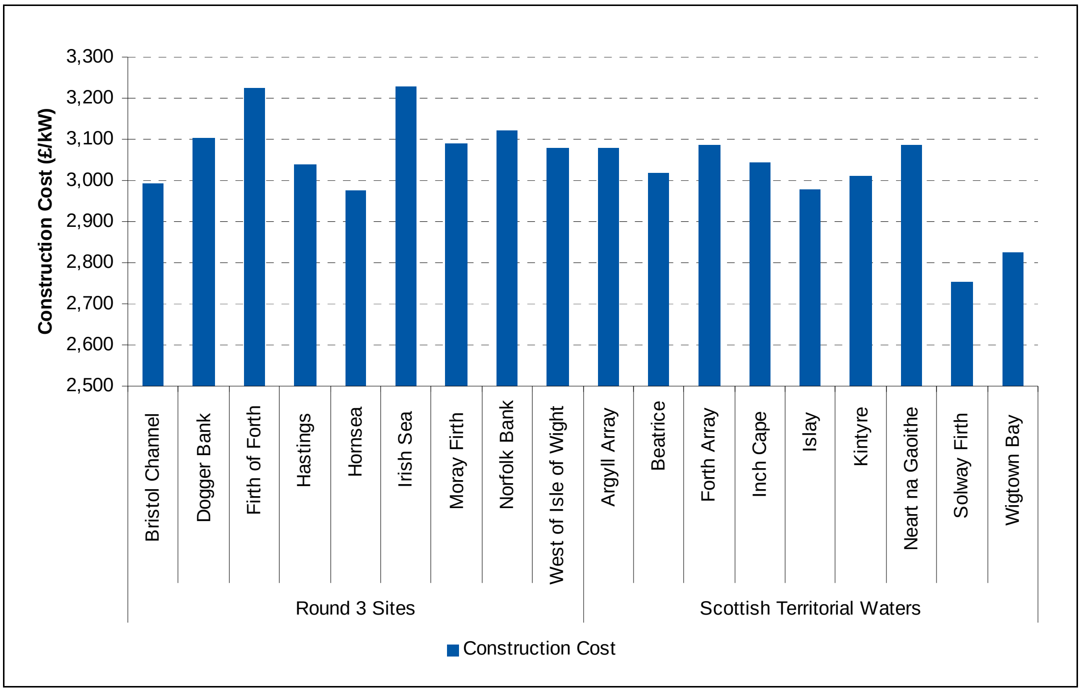
88 http://www.thecrownestate.co.uk/our_portfolio/marine/offshore_wind_energy/round3/r3-developers.htm

Table E.3
Depth Adjustments to Construction Costs, Scottish Territorial Waters

Wind farm	Region	Availability MW	Depth (m) Min	Max	Average	Delta vs Depth Benchmark (m)	Construction Cost Adjustment (£/kW)
Argyll Array	Scotland	1,500	3.0	95.0	49.0	-1.0	-9
Beatrice	Scotland	920	35.0	50.0	42.5	-7.5	-68
Forth Array	Scotland	415	37.0	63.0	50.0	-	-
Inch Cape	Scotland	905	36.0	54.0	45.0	-5.0	-45
Islay	Scotland	680	25.0	51.0	38.0	-12.0	-109
Kintyre	Scotland	378	16.0	67.0	41.5	-8.5	-77
Neart na Gaoithe	Scotland	360	44.0	56.0	50.0	-	-
Solway Firth	North West	300	4.0	23.0	13.5	-36.5	-332
Wigtown Bay	Scotland	280	12.0	30.0	21.0	-29.0	-264

Source: 4COffshore.com. Benchmark depth for Round 3 developments is 50m.

Figure E.5
Differentiated Construction Costs in 2009 excl. Infrastructure



E.2.2. Infrastructure costs

The £/kW/year costs for each offshore project that we considered are summarised below:

Table E.4
Offshore Transmission Investment Costs

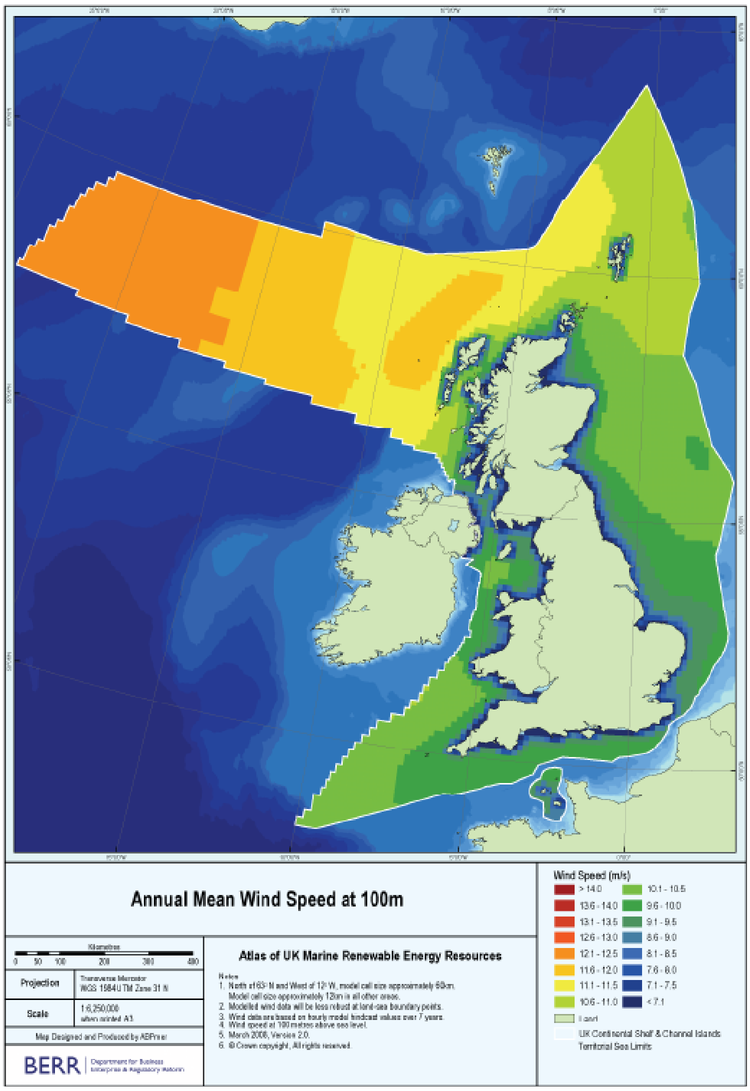
	Tariff (£/kW/year)
Galloper Wind Farm	46.00
Kentish Flats 2	11.00
Thanet 2	11.30
Burbo Bank Extension	20.00
Walney Extension	14.00
Bristol Channel	28.7
Dogger Bank	47.7
Firth of Forth	30
Hastings	36.8
Hornsea	47.7
Irish Sea	32.9
Moray Firth	38.6
Norfolk Bank	34.9
Isle of Wight	35
Argyll Array	7.5
Beatrice	24
Forth Array	21.2
Inch Cape	19
Islay	16.1
Kintyre	4
Neart na Gaoithe	17.5
Solway Firth	11.3
Wigtown Bay	6

Source: NERA/Imperial Analysis and National Grid

E.2.3. Load factors and production profiles

To forecast wind load factors and production profiles for offshore sites, we used the same mathematical relationship between wind intensity (i.e. average wind speed) and load factor that we use for onshore wind capacity described above. However, the DECC wind speed database does not cover offshore locations, so instead we estimated average annual wind speeds for offshore sites using the "wind atlas" in Figure E.6. We then converted these wind speeds into load factors as shown in Table E.5.

Figure E.6
GB Wind Speed Atlas



Source: The Renewables Atlas (2008)[89]

Table E.5
Estimated Annual Load Factors by Offshore Area

Zone Number	Wind farm	Region	Wind Speed (m/s) Min	Max	Wind Intensity W/m2	Load Factor CT Relationship
8	Bristol Channel	South West	9.6	10	1,050	47%
3	Dogger Bank	North Sea	10.1	10.5	1,150	50%
2	Firth of Forth	Scotland	10.1	10.5	1,150	50%
6	Hastings	South	9.1	10	950	44%
4	Hornsea	North Sea	9.1	10	950	44%
9	Irish Sea	Irish Sea	9.6	10.5	1,050	47%
1	Moray Firth	Scotland	9.6	10	950	44%
5	Norfolk Bank	Southern North Sea	9.6	10	950	44%
7	West of Isle of Wight	South	9.6	10	950	44%

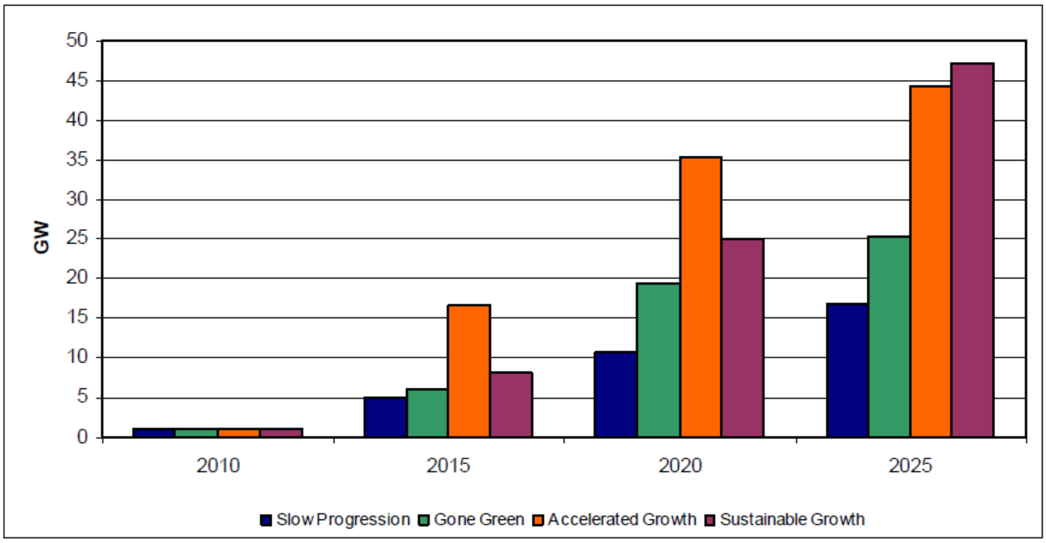
89 http://www.renewables-atlas.info/downloads/documents/Renewable_Atlas_Pages_A4_April08.pdf

Source: NERA Calculations based on estimates from The Renewables Atlas (2008). Wind speeds converted into wind intensity using the convention applied by the Carbon Trust (2008) using a Weibull distribution with shape parameter of K=2.2.

E.2.4. Capacity and resource potential

We adopted the "sustainable growth" scenario used by National Grid in its September 2010 offshore development statement (see Figure E.7) as a measure of the maximum annual build rate achievable for offshore wind turbines. This scenario is what Renewables UK estimates "will encourage the establishment of a long-term manufacturing industry within the UK".[90] This implies a growth rate up to 2020 of around 3.4GW per annum, and 4.4GW per annum after 2025. By 2025, these assumed build rates lead to a total volume of installed wind capacity close to the total volume currently in development (see Table E.6). Between 2025 and 2030, we assumed that the maximum annual deployment of offshore wind continues to grow at the same rate as between 2020 and 2025.

Figure E.7
Build Rate Scenarios: NG Offshore Development Statement



Source: National Grid Offshore Development Statement 2010[91]

[90] Offshore Development Information Statement, National Grid, September 2010, page 47.

[91] https://www.nationalgrid.com/NR/rdonlyres/14BFDA91-01E7-49A2-82CB-A7151155D12F/43325/2010ODIS_Chapters_Final.pdf

Table E.6
Offshore Wind Capacity in Development

	Operating	Under Construction	Approved	Submitted	Planned	Total
Round 1 and earlier	977	155	62	-	-	1,194
Round 2	365	1,004	2,530	3,460	-	7,359
Round 1+2 Extension	-	-	-	-	1,686	1,686
Scottish Territorial Waters	-	-	-	-	5,738	5,738
Round 3	-	-	-	-	32,200	32,200
Total	1,342	1,159	2,592	3,460	39,624	48,177

Source: BWEA Offshore Wind Farms 2010[92] *and National Grid Offshore Development Statement 2010*

To estimate the resource potential at individual offshore sites, we allocate the total offshore resource potential we assume in proportion to the capacity that Renewables UK estimates could be developed at each Round 2 and Round 3 site, as well as the capacity that the Scottish government has estimated could be developed in Scottish Territorial Waters.[93]

[92] http://www.bwea.com/ukwed/offshore.asp

[93] See (1) http://www.bwea.com/ukwed/offshore.asp and
(2) http://www.scotland.gov.uk/Publications/2010/05/14155221/2

Appendix F. Forecast TNUoS Charges

Table F.1: Locational Generation TNUoS Charges (2010 £/kW/yr)

	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Charging Zone 1	21.1	20.9	27.5	26.9	37.6	36.3	35.2	31.5	34.2	35.6	39.6
Charging Zone 2	20.1	19.6	26.1	23.9	38.7	37.1	35.9	30.9	33.8	35.0	39.2
Charging Zone 3	21.1	21.7	28.5	27.9	38.3	37.0	36.1	32.7	35.3	36.9	40.4
Charging Zone 4	17.7	17.0	23.6	22.5	33.5	32.7	31.7	28.0	30.7	32.2	36.0
Charging Zone 5	15.7	15.4	22.8	21.6	29.6	29.4	28.8	26.2	28.9	30.8	34.2
Charging Zone 6	14.8	14.5	21.7	20.8	28.7	27.9	27.1	24.4	26.9	28.6	32.3
Charging Zone 7	13.0	12.8	18.9	18.0	21.3	19.9	19.4	17.6	20.9	22.5	24.3
Charging Zone 8	16.8	16.3	22.5	22.3	26.8	26.7	26.2	24.1	26.7	28.8	32.4
Charging Zone 9	5.5	4.9	2.9	2.4	0.5	0.3	0.2	0.4	0.2	-0.4	-2.2
Charging Zone 10	8.4	7.9	7.8	7.7	5.0	5.1	4.9	3.7	4.0	4.0	3.6
Charging Zone 11	6.6	6.1	0.5	-0.3	-0.7	-1.0	-0.7	-0.1	-0.7	-0.1	-3.8
Charging Zone 12	6.0	5.5	0.5	-0.3	-0.7	-1.4	-1.2	-0.6	-1.3	-0.7	-4.4
Charging Zone 13	3.1	2.7	-0.4	-0.6	-2.1	-2.2	-2.2	-2.0	-2.0	-2.7	-4.6
Charging Zone 14	0.6	0.0	-3.0	-3.1	-4.4	-4.5	-4.6	-3.6	-3.9	-3.5	-3.6
Charging Zone 15	-0.3	1.9	-0.7	-0.1	-1.9	-3.3	-2.7	-2.5	-2.4	-2.5	-2.6
Charging Zone 16	-7.0	-7.3	-10.4	-10.0	-11.4	-11.2	-12.3	-11.1	-10.8	-11.6	-9.9
Charging Zone 17	-1.9	-2.2	-5.2	-4.5	-5.4	-4.9	-5.3	-4.2	-3.8	-4.7	-1.6
Charging Zone 18	-2.8	-2.8	-6.6	-6.6	-8.3	-8.2	-8.8	-7.8	-7.6	-8.6	-8.7
Charging Zone 19	-3.7	-3.8	-6.9	-7.3	-9.0	-10.9	-10.5	-10.7	-10.6	-10.9	-10.3
Charging Zone 20	-5.6	-5.6	-8.6	-8.7	-10.4	-12.9	-9.9	-10.0	-9.9	-9.9	-9.7

Source: NERA/Imperial Analysis

Table F.2: Uniform Generation TNUoS Charges (2010 £/kW/yr)

	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Uniform Charge	5.45	5.38	5.42	5.85	6.41	6.21	6.58	6.86	8.05	7.75	8.23

Source: NERA/Imperial Analysis

Table F.3: Locational Demand TNUoS Charges (2010 £/kW/yr)

	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Northern Scotland	2.97	3.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern Scotland	8.16	8.47	1.79	2.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern	13.11	13.53	13.62	14.18	17.58	16.50	16.79	17.19	16.98	16.65	16.36
North West	16.77	17.28	19.67	20.48	21.88	21.44	21.54	21.23	21.46	21.03	22.28
Yorkshire	16.86	17.61	19.97	20.51	22.36	21.64	21.79	22.34	22.58	22.96	24.02
N Wales & Merseyside	17.50	17.96	22.29	23.15	24.15	23.86	23.88	23.12	23.60	21.91	24.27
East Midlands	20.20	20.58	23.60	24.17	25.66	24.93	25.20	24.52	24.35	24.03	25.27
Midlands	20.89	21.37	24.66	25.38	26.70	26.34	26.34	25.68	25.93	24.38	25.46
Eastern	21.93	22.35	25.34	25.37	26.55	25.66	26.12	24.90	24.60	25.23	24.09
South Wales	22.16	19.10	22.05	21.72	23.37	23.79	23.27	22.90	22.78	22.43	21.73
South East	25.35	25.54	28.79	28.28	29.81	28.71	29.45	28.28	28.12	28.34	24.53
London	29.00	29.38	32.49	31.92	31.99	30.60	31.17	29.61	29.41	29.80	24.10
Southern	25.17	25.27	28.58	28.81	30.75	30.14	30.51	29.66	29.57	29.62	28.98
South Western	24.85	24.89	27.83	27.88	29.57	30.90	29.14	28.99	28.92	28.39	27.52

Source: NERA/Imperial Analysis

Table F.4: Uniform Demand TNUoS Charges (2010 £/kW/yr)

	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Northern Scotland	3.70	3.81	0.71	2.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern Scotland	8.88	8.93	5.73	7.17	2.51	2.78	0.00	1.42	0.64	2.73	2.69
Northern	13.83	14.10	15.56	16.48	17.78	18.00	18.20	19.06	20.53	21.37	20.63
North West	17.49	17.78	21.16	21.62	24.88	23.50	26.71	25.35	28.12	27.71	26.83
Yorkshire	17.59	18.14	21.32	21.77	24.87	24.08	26.62	26.31	28.87	28.82	27.86
N Wales & Mersey	18.20	18.40	23.31	23.32	27.91	26.19	30.69	28.15	31.58	30.65	29.59
East Midlands	20.92	21.30	24.95	25.47	28.95	27.95	30.84	29.71	32.49	32.22	31.26
Midlands	21.52	21.76	25.84	26.38	29.90	28.56	31.83	30.19	33.18	32.57	31.58
Eastern	22.70	23.20	26.73	27.23	30.58	29.72	32.45	31.62	34.33	34.30	33.37
South Wales	22.00	19.56	23.42	24.13	27.89	27.92	30.92	29.48	32.29	31.95	30.93
South East	26.16	26.50	30.17	31.06	34.48	33.62	36.46	35.01	37.80	37.04	36.14
London	29.78	30.28	33.87	34.50	37.89	37.02	39.81	38.76	41.50	41.35	40.43
Southern	26.02	26.22	29.95	30.85	34.29	33.47	36.38	35.08	37.83	37.02	35.91
South Western	25.86	25.40	29.19	30.21	33.61	33.03	35.55	34.17	36.77	34.83	33.59

Source: NERA/Imperial Analysis

Appendix G. Forecast Generation Capacity

Table G.1
Projected Installed Capacity by Technology (MW) – Locational Scenario

		Baseline Capacity Assumptions											Modelled New Investment		
	Peak Load	*Coal*	*CCGT*	*Nuclear*	*CHP*	*Renewables*	*Pumped Storage*	*Oil*	*Hydro*	*Waste*	*OCGT*	*Other*	*CCGT*	*OCGT*	*Renewables*
2008	65,747	28,567	25,503	10,894	4,169	3,874	2,744	2,695	1,436	478	429	1,745	0	0	0
2009	65,440	28,567	27,203	10,894	4,169	3,996	2,744	2,695	1,436	478	429	1,745	0	0	0
2010	65,520	27,631	28,913	10,894	4,169	6,101	2,744	2,695	1,511	478	429	1,745	0	0	0
2011	64,639	25,782	32,248	10,424	4,169	7,224	2,744	2,695	1,511	478	429	1,745	0	0	1,850
2012	64,891	23,859	31,879	10,424	4,169	7,594	2,744	2,695	1,511	478	429	1,745	0	0	3,116
2013	66,328	21,750	31,144	9,444	4,169	8,452	2,744	2,695	1,511	478	429	1,745	0	0	5,160
2014	67,021	19,828	30,076	9,444	4,169	9,286	2,744	2,695	1,511	478	429	1,745	1,230	300	7,204
2015	67,181	19,828	27,302	9,444	4,169	10,135	2,744	2,695	1,511	478	429	2,645	1,230	300	9,247
2016	67,841	19,828	25,427	9,444	4,169	10,404	2,744	453	1,511	478	297	2,645	7,390	3,000	10,547
2017	67,794	19,828	25,662	7,034	4,169	10,673	2,744	453	1,511	478	152	2,645	9,496	3,900	11,846
2018	68,519	19,828	25,662	7,034	4,169	10,942	2,744	453	1,511	478	140	2,645	9,496	3,900	13,146
2019	70,064	19,828	25,992	4,684	4,169	11,211	2,744	453	1,511	478	140	2,645	9,496	3,900	14,445
2020	71,245	19,828	25,992	4,684	4,169	11,480	2,744	453	1,511	478	140	2,645	12,754	3,900	15,745
2021	71,972	19,828	25,992	3,603	4,169	11,501	2,744	453	1,511	478	140	2,645	12,754	3,900	15,745
2022	72,158	19,828	25,992	3,603	4,169	11,523	2,744	453	1,511	478	140	2,645	12,754	3,900	16,035
2023	73,480	19,828	25,992	3,603	4,169	11,546	2,744	453	1,511	478	140	2,645	12,754	3,900	16,097
2024	74,691	4,759	25,763	3,603	4,169	11,566	2,744	453	1,511	478	140	2,645	16,809	4,800	16,282
2025	76,582	4,759	25,763	3,603	4,169	11,580	2,744	453	1,511	478	140	2,645	21,663	6,000	16,282
2026	77,229	4,759	25,503	1,200	4,169	11,594	2,744	453	1,511	478	140	2,645	21,663	6,000	16,473
2027	78,377	4,759	25,503	1,200	4,169	11,608	2,744	453	1,511	478	140	2,645	21,663	6,000	16,473
2028	78,561	2,938	23,410	1,200	4,027	11,622	2,744	453	1,511	478	140	2,645	23,285	9,000	16,664
2029	80,028	798	22,202	1,200	3,805	11,636	2,744	453	1,511	478	140	2,645	23,285	9,000	16,664
2030	81,806	496	21,505	1,200	3,786	11,650	2,744	453	1,511	478	140	2,645	23,285	9,000	17,018

Source: NERA/Imperial Analysis

Table G.2
Projected Installed Capacity by Technology (MW) – Uniform Scenario

		Baseline Capacity Assumptions											Modelled New Investment		
	Peak Load	*Coal*	*CCGT*	*Nuclear*	*CHP*	*Renewables*	*Pumped Storage*	*Oil*	*Hydro*	*Waste*	*OCGT*	*Other*	*CCGT*	*OCGT*	*Renewables*
2008	65,747	28,567	25,503	10,894	4,169	3,874	2,744	2,695	1,436	478	429	1,745	0	0	0
2009	64,134	28,567	27,203	10,894	4,169	3,996	2,744	2,695	1,436	478	429	1,745	0	0	0
2010	63,286	27,631	28,913	10,894	4,169	6,101	2,744	2,695	1,511	478	429	1,745	0	0	0
2011	62,349	25,708	32,248	10,424	4,169	7,224	2,744	2,695	1,511	478	429	1,745	0	0	1,850
2012	62,858	22,852	32,648	10,424	4,169	7,594	2,744	2,695	1,511	478	429	1,745	1,225	0	3,116
2013	64,465	21,750	31,408	9,444	4,169	8,452	2,744	2,695	1,511	478	429	1,745	1,625	300	5,066
2014	65,474	19,828	30,856	9,444	4,169	9,286	2,744	2,695	1,511	478	429	1,745	5,718	2,100	7,016
2015	65,788	19,828	27,941	9,444	4,169	10,135	2,744	2,695	1,511	478	429	2,645	5,718	2,100	8,966
2016	66,393	19,828	25,792	9,444	4,169	10,404	2,744	453	1,511	478	297	2,645	5,718	2,100	10,172
2017	66,341	17,854	26,027	7,034	4,169	10,673	2,744	453	1,511	478	152	2,645	9,065	2,400	11,378
2018	67,143	17,854	24,152	7,034	4,169	10,942	2,744	453	1,511	478	140	2,645	9,065	2,400	12,584
2019	68,831	17,854	24,282	4,684	4,169	11,211	2,744	453	1,511	478	140	2,645	11,497	3,000	13,789
2020	70,090	17,854	24,282	4,684	4,169	11,480	2,744	453	1,511	478	140	2,645	11,497	3,000	14,995
2021	71,000	17,854	24,282	3,603	4,169	11,501	2,744	453	1,511	478	140	2,645	11,497	3,000	14,995
2022	71,385	16,895	24,282	3,603	4,169	11,523	2,744	453	1,511	478	140	2,645	11,497	3,300	15,285
2023	72,932	16,895	24,282	3,603	4,169	11,546	2,744	453	1,511	478	140	2,645	11,497	5,100	15,347
2024	74,290	2,785	24,282	3,603	4,169	11,566	2,744	453	1,511	478	140	2,645	14,741	6,600	15,533
2025	76,175	2,785	24,282	3,603	4,169	11,580	2,744	453	1,511	478	140	2,645	18,795	9,600	15,533
2026	76,825	2,785	24,072	1,200	4,169	11,594	2,744	453	1,511	478	140	2,645	18,795	9,600	15,724
2027	77,972	2,785	24,053	1,200	4,169	11,608	2,744	453	1,511	478	140	2,645	18,795	9,600	15,724
2028	78,162	964	21,607	1,200	4,027	11,622	2,744	453	1,511	478	140	2,645	20,417	12,300	15,914
2029	79,627	798	21,607	1,200	3,805	11,636	2,744	453	1,511	478	140	2,645	20,417	12,300	15,914
2030	81,399	496	21,607	1,200	3,786	11,650	2,744	453	1,511	478	140	2,645	20,417	12,300	16,268

Source: NERA/Imperial Analysis

Table G.3
Cumulative New Generation by Zone (GW) – Locational Scenario

Charging Zone	OCGT	CCGT	Nuclear	Wind	CCS	Biomass
1	0.0	0.0	0.0	0.7	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.7	0.0	0.0
4	0.0	0.0	0.0	0.2	0.0	0.0
5	0.0	0.0	0.0	4.1	0.0	0.1
6	0.0	0.0	0.0	0.2	0.7	0.3
7	0.0	0.0	0.0	0.8	0.0	0.6
8	0.0	0.0	0.0	0.8	0.0	0.3
9	0.0	0.0	0.0	1.2	0.4	0.0
10	0.0	0.0	0.0	0.1	0.0	0.0
11	0.0	0.0	6.1	0.2	0.0	0.0
12	0.0	0.0	0.0	0.2	0.0	0.0
13	0.0	0.6	0.0	0.2	0.0	0.2
14	0.6	1.4	0.0	0.2	0.0	0.0
15	0.0	2.4	0.0	3.2	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0
17	6.3	14.3	0.0	0.1	0.0	0.0
18	0.5	0.4	0.0	0.0	0.0	0.0
19	0.0	0.0	0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0

Source: NERA/Imperial Analysis

Table G.4
Cumulative New Generation by Zone (GW) – Uniform Scenario

Charging Zone	OCGT	CCGT	Nuclear	Wind	CCS	Biomass
1	1.4	2.6	0.0	1.6	0.0	0.0
2	1.4	2.6	0.0	0.1	0.0	0.0
3	0.0	0.0	0.0	1.4	0.0	0.0
4	0.0	0.0	0.0	0.3	0.0	0.0
5	0.0	0.0	0.0	4.1	0.0	0.1
6	1.4	2.6	0.0	0.2	0.7	0.3
7	0.0	0.0	0.0	0.6	0.0	0.6
8	0.0	0.0	0.0	0.6	0.0	0.3
9	0.7	1.3	0.0	2.5	0.4	0.0
10	1.4	2.6	0.0	0.0	0.0	0.0
11	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0
13	0.5	0.9	0.0	0.1	0.0	0.2
14	0.5	0.9	0.0	0.1	0.0	0.0
15	1.4	2.6	1.5	0.1	0.0	0.0
16	0.0	0.0	0.0	0.0	0.0	0.0
17	0.0	0.0	3.1	0.0	0.0	0.0
18	0.0	0.0	0.0	0.0	0.0	0.0
19	0.0	0.0	3.1	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0	0.0

Source: NERA/Imperial Analysis

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